CURIS RESOURCES (ARIZONA) INC.

14 December 2012
File No. 38706-119

Ms. Nancy Rumrill
U.S. Environmental Protection Agency
Region 9, Ground Water Office, WTR-9
75 Hawthorne Street
San Francisco, California 94105-3901

Re: Response to Request for Information dated November 8, 2012
Class III Underground Injection Control (UIC) Well Permit Application
Curis Resources (Arizona) Inc.

Dear Ms. Rumrill:

Curis Resources (Arizona), Inc. (Curis Arizona) is pleased to submit the following in response to Mr. David Albright's November 8, 2012 letter to Mr. Michael McPhie and to the Requests for Information (RFIs) included as an attachment to Mr. Albright's letter. Curis Arizona's responses to each of the 12 comments identified in the RFI are provided below. Each RFI is listed in italics and is followed by our response.

We believe the following is responsive to the RFI and we are available to answer any questions you might have.

Thank you for your assistance.

Sincerely,
Curis Resources (Arizona) Inc.

Daniel Johnson
Vice President – General Manager

cc: Richard Mendolia, Arizona Department of Environmental Quality
David Albright, U.S. Environmental Protection Agency
Michael McPhie, Curis Arizona

ATTACHMENT A, AREA OF REVIEW

1. *A.2.1, Hydraulic Control: The description of the proposed Area of Review (AOR) as 500 feet horizontally beyond the PTF well field area is inconsistent with the distance shown on Figure Temp APP RTC (E) 18-1 in Attachment 3 of the May 23 response to Arizona Department of Environmental Quality (ADEQ) comments of May 2,2012. The 500-foot circumscribing area around the PTF ("buffer area of PTF well field") shown on that map is 500 feet from the outer recovery wells in the PTF, not from the perimeter of the PTF well field area as drawn on that map. If the AOR boundary were drawn 500 feet from the PTF well field area perimeter, additional wells and coreholes would be located within the AOR and would require corrective action considerations.*

   Please clarify the description of the PTF well field area and modify Figure 18-1 to be consistent with that description if the proposed AOR boundary is 500 feet from the perimeter of the well field area as labeled in Figure 18-1, as opposed to 500 feet from the outer recovery wells. Please provide the basis for your response considering the UIC regulations at 40 CFR Part 146.6(a)(ii), which describe the AOR for an area permit as the lateral distance from the perimeter of the project area. Also, the March 2011 UIC permit application describes the AOR boundary as 500 feet from the perimeter of the 212-acre ISCR area rather than 500 feet from any specific well in the well field.

Response to Comment 1

Figure APP RTC (E) 18-1 has been revised to reflect the PTF well field boundary used to create the AOR shown on that Figure, and is provided in Attachment 1. The PTF well field boundary originally shown on this figure was an administrative boundary that included surface features such as roads, pipeline corridors, and electrical infrastructure associated with the PTF well field, but that does not exert hydrologic influence in the subsurface. The revised boundary reflects the limits of the well field as defined by the physical installation of injection, recovery, and hydraulic control observation wells. The boundary shown on the revised Figure APP RTC (E) 18-1 is the boundary that was used to determine the circumscribing 500-foot AOR shown on all Figures.

40 CFR Part 146.6(a)(ii) describes the AOR as the "…lateral distance from the perimeter of the project area, in which the pressures of the injection zone may cause the migration of the injection and/or formation fluid into an underground source of drinking water." It is Curis Arizona's understanding that this description of the AOR refers to project facilities that exert a hydrologic influence in the subsurface, rather than non-hydrologic project infrastructure located at or above ground surface. The injection and recovery wells are the only project infrastructure that have the potential to cause the migration of the injected fluid or formation fluid into an underground source of drinking water, and thus represent the extent of the project area as described in 40 CFR 146.6(a)(ii).

The 212-acre ISCR area described in the March 2011 UIC permit application is not under consideration in conjunction with the current UIC permit application. The March 2011 UIC permit application was revised in scope to cover only Phase 1 of the proposed ISCR operations, as noted in a letter to EPA dated June 1, 2012. However, the following description is provided for the reviewer's convenience.

As noted, the March 2011 UIC permit application describes an AOR boundary that extends 500 feet from the perimeter of the 212-acre ISCR area. The perimeter of the 212-acre ISCR area was defined as a line circumscribing the extent of the economically recoverable resource, which is the planned location of the outermost ISCR wells. It is the intent of Curis Arizona to install ISCR wells up to and at the perimeter of the 212-acre ISCR area, which is fully within the limits of their property. The ISCR area boundary shown in the March 2011 UIC application denotes the spatial limit to which ISCR wells with the potential to exert a hydrologic influence will be installed. The proposed AOR shown in the March 2011 UIC application was created using criteria consistent with the AOR proposed for the PTF well field.

2. *A.3, MODFLOW IMT3D Groundwater Model and Simulation Results: The Curis Arizona response to Comment 2 of our July 2012 letter, regarding the modeling results for assessment of hydraulic control, does not address the question of the extent of vertical movement of the lixiviant within the Sidewinder and other fault zones with lack of hydraulic control for 48 hours and up to 30 days. Figures 2-1 to 2-8 depict fluid movement horizontally in the fault zone in a north-south view across the PTF, but none of the figures show the fault zones in an east-west cross sectional view that could illustrate the extent of vertical fluid movement within the fault zones. The extent of vertical flow within the 10 layers is shown in the figures, but not within the Sidewinder fault zone and other intersecting faults. It is possible that lixiviant could migrate up dip within the more permeable fault zones for a lateral distance exceeding the 500-foot AOR and upward into the LBFU where the faults intersect the contact between the LBFU and Bedrock Oxide Zone.*

   Please provide a discussion and illustrations of the extent of vertical migration of lixiviant within the fault zones under the conditions presented in the responses to Comment 2. Cross-sectional views in an east-west orientation, similar to the cross section in Figure 9-2, should be provided for that purpose.

Response to Comment 2

Figures 2-1 through 2-8 (north-south cross sections) have been revised to reflect the PTF well field area defined above, in response to Comment 1. An additional set of east-west oriented cross sections corresponding to Figures 2-1 through 2-8 have been created and are included as Figures 2-1a through 2-8a. Figures 2-1 through 2-8 and 2-1a through 2-8a depict the extent of migration of injected fluid under conditions defined in the RFI dated January 30, 2012. These conditions were simulated as permutations of the base model which are described in Table 2-1. Figure 2-1 through 2-8 and 2-1a through 2-8a are provided in Attachment 2.

Table 2-1. Supplemental Groundwater Model Scenarios

	Simulation Time	Number of Wells Injecting	Injection Rate (GPM)	Number of Wells Pumping	Pumping Rate	Porosity of Oxide Layers (%)	Fault Zone Porosity (%)	Fault Zone Hydraulic Conductivity (ft/day)	MFGU Hydraulic Conductivity
Scenario 1	30 days	1	60	0	0	Base Model	10	40	Base Model
	48 hours	1	60	0	0	Base Model	10	40	Base Model
Scenario 2	30 days	1	60	0	0	Base Model	13	40	Base Model
Scenario 3	30 days	1	60	0	0	Base Model	20	40	Base Model
Scenario 4	30 days	1	60	0	0	2	Base Model	Base Model	Base Model
Scenario 5	30 days	1	60	0	0	8	Base Model	Base Model	Base Model

Table 2-1. Supplemental Groundwater Model Scenarios									
	Simulation Time	Number of Wells Injecting	Injection Rate (GPM)	Number of Wells Pumping	Pumping Rate	Porosity of Oxide Layers (%)	Fault Zone Porosity (%)	Fault Zone Hydraulic Conductivity (ft/day)	MFGU Hydraulic Conductivity
Scenario 6	30 days	1	60	0	0	13	Base Model	Base Model	Base Model
Scenario 7	30 days	1	60	0	0	13	Base Model	Base Model	Set Equal to LBFU Value

Figures 2-1 through 2-8 and 2-1a through 2-8a depict the extent of vertical and horizontal migration of injected fluid under the conditions described in Table 2-1. A revised description of the model results that includes consideration of the east-west cross sections shown in Figures 2-1a through 2-8a is included below.

Scenario 1: Sidewinder Fault hydraulic conductivity set at 40 feet/day and porosity at 10 percent.

Figure 2-1 provides a cross-sectional view (north-south transect) of vertical and horizontal migration of sulfate from a single well within the PTF well field after operating without hydraulic control for a period of 30 days, and using the fault hydrologic parameters described above. Under these simulated conditions, injectate migrates northward approximately 201 feet horizontally from the PTF injection well, and approximately 40 feet vertically into the exclusion zone. Figure 2-1a shows that injected solution migrated approximately 150 feet to the west in model layer 10. Injected solution did not reach the LBFU in significant concentrations after 30 days without hydraulic control. The estimated horizontal migration distance of 201 feet was the maximum observed from all model scenarios and associated simulations involving 30-day lixiviant injection without hydraulic control.

Figure 2-2 is a cross-sectional view (north-south transect) of vertical and horizontal migration of sulfate from a single well within the PTF well field after operating without hydraulic control for a period of 48 hours, and using a fault hydraulic conductivity of 40 feet/day and porosity of 10 percent. Figure 2-2 shows that under these conditions, after 48 hours, sulfate migrates northward approximately 67 feet horizontally from the PTF injection well along the Sidewinder fault in layer 10, and approximately 40 feet vertically into the exclusion zone. Figure 2-2a shows that injected solution migrated approximately 63 feet to the west in model layer 10. No significant migration of injected solution into the LBFU occurred after 48 hours without hydraulic control. This simulation scenario reflects the greatest estimated extent of lateral migration during a 48-hour period for all scenarios without hydraulic control. Given this fact, only the conservative 30-day simulation results are presented below as measures of maximum lateral and vertical lixiviant migration distances after injecting for 30-days without hydraulic control.

Scenario 2: Sidewinder Fault hydraulic conductivity set at 40 feet/day and fault porosity at 13 percent.

Given the assumed hydraulic parameters described above, the simulated results shown on Figure 2-3 show that lixiviant migrates northward approximately 163 feet horizontally from the PTF injection well along the Sidewinder fault in model layer 10, and approximately 40 feet vertically into the exclusion zone within a very limited lateral extent. Figure 2-3a shows that injected solution migrated approximately 125 feet to the west in model layer 10. Injected solution was not estimated to reach the LBFU in significant concentrations after 30 days without hydraulic control.

Scenario 3: Sidewinder Fault hydraulic conductivity set at 40 feet/day and fault porosity at 20 percent.

Given the assumed hydraulic parameters described above, the simulated results shown on Figure 2-4 show that lixiviant migrates northward approximately 125 feet horizontally from the PTF injection well along the Sidewinder fault in model layer 10, and approximately 40 feet vertically into the exclusion zone within a very limited lateral extent. Figure 2-4a shows that injected solution migrated approximately 100 feet to the east and west in model layer 10. Injected solution did not reach the LBFU in significant concentrations after 30 days without hydraulic control.

Scenario 4: Oxide porosity set at 2 percent. Fault zone hydraulic parameters at base FCP model values.

Given the assumed hydraulic parameters noted above for the oxide unit, the simulated results shown on Figure 2-5 shows that lixiviant migrates northward approximately 125 feet horizontally from the PTF injection well along the Sidewinder fault in model layer 10, and approximately 40 feet vertically into the exclusion zone. The lateral extent of the lixiviant migration is limited to an area within the footprint of the PTF well field. Figure 2-5a shows that injected solution migrated approximately 138 feet to the west in model layer 8. Dilute concentrations of injected solution also migrate vertically upwards approximately 55 feet into the LBFU.

Scenario 5: Oxide porosity set at 8 percent. Fault zone hydraulic parameters at base FCP model values.

Given the assumed hydraulic parameters noted above for the oxide unit, the simulated results shown on Figure 2-6 show that lixiviant migrates northward approximately 125 feet horizontally from the PTF injection well along the Sidewinder fault in model layer 10, approximately 40 feet vertically into the exclusion zone, and approximately 54 feet vertically into the LBFU. The lateral extent of the lixiviant migration is limited to an area within the footprint of the PTF well field. Figure 2-6a shows that injected solution migrated approximately 125 feet to the east and west in model layer 10. The estimated horizontal migration distance is identical to the previous scenarios because the maximum migration distance occurs along the Sidewinder fault zone and the hydraulic parameters for the fault zone are the same in Scenarios 4 through 7.

Scenario 6: Oxide porosity set at 13 percent. Fault zone hydraulic parameters at base FCP model values.

Given the assumed hydraulic parameters noted above for the oxide unit, the simulated results shown on Figure 2-7 show that lixiviant migrates northward approximately 125 feet horizontally from the PTF injection well along the Sidewinder fault in model layer 10, approximately 40 feet vertically into the exclusion zone, and approximately 54 feet vertically into the LBFU. The lateral extent of the lixiviant migration is limited to an area within the footprint of the PTF well field. Figure 2-7a shows that injected solution migrated approximately 125 feet to the east and west in model layer 10. The estimated horizontal migration distance is identical to the previous scenarios because the maximum migration distance occurs along the Sidewinder fault zone and the hydraulic parameters for the fault zone are the same in Scenarios 4 through 7.

Scenario 7: No MFGU – MFGU given hydraulic parameters of LBFU.

Given the assumed hydraulic parameters noted above for the MFGU, the simulated results shown on Figure 2-8 show that lixiviant migrates north and south approximately 125 feet horizontally from the PTF injection well along the Sidewinder fault in model layer 10, approximately 40 feet vertically into the exclusion zone, and approximately 52 feet vertically into the LBFU. The lateral extent of the lixiviant migration is limited to an area within the footprint of the PTF well field. Figure 2-7a shows that injected solution migrated approximately 125 feet to the east and west in model layer 10. The estimated horizontal migration distance is identical to the previous scenarios because the maximum migration distance occurs along the Sidewinder fault zone and the hydraulic parameters for the fault zone are the same in Scenarios 4 through 7.

In summary, the maximum horizontal migration distance estimated with the FCP model, given the specified variations in hydraulic and transport parameters and loss of hydraulic control for 30 days, was approximately 201 feet horizontally within the fault zone of model layer 10 (deepest model layer) and 55 feet vertically into the LBFU. Minimum transport distances for the above 30-day scenarios were approximately 125 feet horizontally and zero feet vertically above the exclusion zone. No significant sulfate mass was estimated to penetrate into the MFGU nor the upper portion of the LBFU. When considering loss of hydraulic control for 48 hours, the maximum estimated horizontal migration distance of lixiviant was only approximately 67 feet along the deepest model layer (layer 10 within the fault zone). Increasing hydraulic conductivities and porosities within the Sidewinder fault zone, decreased porosity values within the oxide unit, and the lack of a confining unit demonstrated no adverse sensitivity effect or undue impact upon vertical or horizontal migration of injected solutions without hydraulic control.

It should be noted that under no circumstances will Curis Arizona continue to inject lixiviant after determination of loss of hydraulic control. If hydraulic control is lost, Curis Arizona will cease injection upon determination of loss of hydraulic control and will not resume injection until hydraulic control has been reestablished. Model scenarios simulating injection without hydraulic control extending from initiation of injection, through 48 hours to a total of 30 days were developed at the request of EPA; however, they do not represent planned PTF operations. Model runs conducted in response to RFI comments assumed injection would continue for periods of up to 30 days without hydraulic control. Injection without hydraulic control for such extended periods is not realistic. Attachment K of the March 2011 UIC Permit application specifies that hydraulic control will be monitored daily and the responses Curis Arizona will take to the loss of hydraulic control are summarized in Table K-1 of that attachment.

ATTACHMENT C, CORRECTIVE ACTION PLAN & WELL DATA

3. *<u>Well and Corehole Construction Data</u>: Table 3-1 is a listing of the well and corehole construction data for each of the wells and coreholes within the AOR. Appendix A contains the available well and corehole construction and cementing records for wells and coreholes within the AOR. EPA will require additional steps to address the following issues although no additional information is needed at this time.*

   Annular Cementing records are not available for 28 of the total 38 coreholes:

   - *Twelve of those without annular cementing records were also reportedly plugged and abandoned with Type V cement from bottom to surface.*
     - *Casing was pulled in eight of the abandoned coreholes prior to plugging operations, and then cement plugs were added to fill the entire diameter and length of those coreholes.*
     - *For the remaining four abandoned coreholes where the casing was not pulled and the annular cementing records are not available, the coreholes may need to be replugged if the borehole/casing annulus was not filled with cement. Based on the drilling and plugging records, the casing was set well above the top of the Bedrock Oxide Zone in each of the coreholes. Remedial cementing may be necessary to ensure isolation in the annulus of the UBFU from the LBFU.*

Annular cementing records are not available for 16 of the unplugged coreholes, and casing records are not available for 11 of the unplugged coreholes. EPA will require additional steps to determine corehole conditions to properly P&A these coreholes.

Casings in four of the six wells listed in Table 3-1 were apparently sealed with bentonite grout, and cementing records are missing for the other two wells. Because bentonite grout can be inadequate for long-term zone isolation purposes, remedial cementing will be necessary during P&A operations to place cement in the borehole/casing annulus at the Bedrock Oxide Zone LBFU interface to ensure isolation of the injection zone from the LBFU and USDWs above the injection zone.

Response to Comment 3

Curis Arizona understands that EPA is not requesting additional information regarding this item at this time, and that EPA may require additional steps to address the issues identified in this comment with regard to P&A of existing wells and coreholes.

4. *Plugging and Abandonment Plans for Corrective Action Purposes: EPA is not requesting information for this item at this time. EPA Form 7520-14, Plugging and Abandonment (P&A) Plans for the coreholes and wells within the AOR as depicted in Figure 18-1 and listed in Table 3-1 are included in Appendix G. Prior to final approval granted for P&A plans, EPA will require a final review and supplemental detailed procedures. If the 500-foot radius AOR is measured from the perimeter of the PTF well field area, as labeled in Figure 8-1, additional coreholes and wells within the larger AOR will require corrective action considerations.*

Response to Comment 4

Curis Arizona understands that EPA is not requesting additional information regarding this item at this time, and that EPA may require supplemental detailed procedures prior to final approval of P&A plans.

ATTACHMENT K, INJECTION PROCEDURES

5. *Operations Plan: The Operations Plan has been updated as requested to remove reference to Phase 2 operations and account for the modifications to the proposed PTF operations and its relocation. The revised plan is provided in Appendix B of the September 10, 2012 response document. Please provide a revision to the Plan with the following changes for purposes of clarity and omission of figures comparable to Figures 1 and 2 in the original Operations Plan presented in Appendix D of the Area Permit issued to BHP Copper in 1997.*

   For clarification in Section 2.2.2.2, Hydraulic Control, please add a sentence to clarify that the paired wells along the perimeter of the IRZ include an outer observation well and an inner recovery well. Please revise Figures 1 and 2 as necessary to represent the PTF operation and configuration, and add them to the amended Operations Plan.

Response to Comment 5

A revised Operations Plan is included as Attachment 3. The Operations Plan has been revised to indicate that paired wells along the perimeter of the PTF well field include an outer observation well and an inner recovery well. The Plan has also been revised to include Figures 1 and 2 similar to those included in the BHP Copper Operations Plan.

ATTACHMENT L AND M, WELL CONSTRUCTION PROCEDURES AND DETAILS

6. *Cementing Procedures and Centralizer Placement: Curis Arizona revised Section 9A.3.2.5 and Drawing 9A.1 of the APP application in response to EPA's comments. In the response, a clarification is needed regarding the discussion of tremie pipe procedures.*

   The last sentence in the last paragraph in Response 6 on page 10 " … the tremie pipe will be removed from the well and …. " is inconsistent with the context of the paragraph, which discusses procedures for cementing the steel casing/borehole annulus. A tremie pipe will not be used to pump cement for that purpose. Please clarify the discussion. Also, please note that a demonstration of a "suitable Type V substitute" cement as described on page 10 will be subject to EPA approval.

Response to Comment 6

In response to Comment 6, Section 9A.3.2.5 has been revised and is included in its entirety below. Revised text is shown in **bold type face**.

9A.3.2.5 Cementing

9A.3.2.5.1 Cementing Characteristics Injection and Recovery Wells

PTF Injection and Recovery wells will be drilled in two stages. The upper stage will consist of a boring drilled from land surface to a point at least 40 feet below the top of bedrock, in which a steel casing will be cemented in place extending from ground surface to a point at least 40 feet below the top of bedrock. The steel casing will be cemented by the plug displacement method.

The lower section of each injection and recovery boring will be drilled from the bottom of the cemented steel casing to the design depth. After well screen and annular materials have been emplaced in the lower section of the boring by tremie, cementing of the upper section of the inner casing, **inside the outer steel casing,** from the bottom of the bedrock exclusion zone to ground surface, will be accomplished by pumping a cement slurry down a tremie pipe positioned with the pipe's lower end near the bottom of the exclusion zone, forcing the cement to fill the annular space between the inner casing and outer steel casing from the bottom up to the surface.

9A.3.2.5.2 Cementing Characteristics, Observation and Westbay Wells

The Observation and Westbay borings will be of a constant diameter, drilled in a single stage, and thus cannot be grouted by the plug displacement method. Once the well casing, screen, and filter pack have been installed in the boring, cementing of the upper portion of the well casing, from the bottom of the bedrock exclusion zone to ground surface, will be accomplished by pumping a cement slurry down a tremie pipe positioned with the pipe's lower end near the bottom of the exclusion zone, forcing the cement to fill the annular space between the borehole and casing from the bottom up to the surface.

9A.3.2.5.3 Cementing Characteristics All Wells

Cement grout will be placed to completely fill the well annulus within the specified interval. Prior to pumping, the cement grout will be passed through a ½-inch slotted bar strainer in order to remove any unmixed lumps. **In cases where a tremie pipe is used (observation wells, westbay wells, and between the steel outer casing and inner fiberglass casing of the injection and recovery wells) during** cement grout installation, the discharge end of the tremie pipe will be continuously submerged in the grout until the zone to be grouted is completely filled.

The well casing will be hung in tension until the cement grout has cured. The well casing will be filled with a fluid of sufficient density to maintain an equalization of pressures to prevent collapse of the well casing during cementing.

Cement will consist of sulfate-resistant Portland Type V cement, unless Curis Arizona submits the following information to the Director regarding a Type V substitute. A suitable Type V substitute will meet the following requirements:

1. The results of an immersion test for resistance to pregnant leach solution or equivalent mass samples of Type V cement and any proposed substitute;
2. A comparison of the percentage weight change between samples;
3. An acceptable substitute will experience little visual change, a weight loss or gain within 5% to 8%, and no significant change in compressive strength; and
4. Upon completion of this demonstration, **and subject to EPA approval**, a substitute cement that meets these criteria may be substituted for Type V cement for well construction.

Water and/or appropriate mud-breaker chemicals will be circulated through the tremie pipe prior to cementing to reduce drilling mud viscosity and assist in removal of mud from the borehole-casing annulus.

The cement slurry will be pumped at the greatest flow rate possible, to promote removal of bentonite mud from the annular space, and enhance bonding between the cement and the casing and formation. An excess quantity of cement will be pumped into the annular space in order to verify "clean" cement slurry returns from the well prior to terminating the cementing procedure. Following installation of the cement slurry, the cement will be allowed to cure for a minimum of 24 hours before performing additional operations on the well.

ATTACHMENT N, CHANGES IN INJECTION FLUID

7. *Changes in Pressure of Injection Zone: The Sidewinder Fault illustrated in Figure 9-2 is shown without an overlap between layers 8 and 9. That results in a discontinuity in the fault between those layers that would inhibit fluid flow in the fault zone. The geologic cross sections provided in the supplemental response to comments (Attachment 13 of the May 23,2012 response to ADEQ comments) depict the Sidewinder fault and two additional faults as continuous in the view looking north at the PTF well field.*

   If there is no discontinuity, please modify the model to represent the unbroken configuration of the Sidewinder Fault Zone, or provide an explanation for the representation and how it was considered in the model.

The Rattlesnake and Thrasher Faults are shown to intersect the wells in the PTF well field above the Sidewinder Fault in the upper layers of the proposed injection interval in the Oxide Bedrock Zone. We are not aware that those faults and their effects on the PTF operations have been included in the predictive simulations for hydraulic control and post-closure discharge impact area.

Please provide a discussion of the possible effects of these fault zones on hydraulic control and potential migration of lixiviant beyond the PTF project area and/or into the LBFU and UBFU.

Response to Comment 7

The Sidewinder fault is assumed to extend the entire distance over which it has been mapped without any discontinuity. However, the Sidewinder fault zone ranges in width from approximately 100 to 300 feet at locations where it has been identified in core logs. The Sidewinder fault was simulated in the groundwater flow model based a geologic model that was constructed from core logs. Consequently where the fault zone thins, a reduced fault zone thickness is represented in the groundwater model. During construction of the groundwater flow model, an effort was made to ensure that at least two cells overlapped at any location where core logs showed that the Sidewinder fault thinned.

In response to Comment 7, Brown and Caldwell preformed a review of the representation of the Sidewinder fault in the groundwater flow model. That review showed that four model rows out of approximately two hundred used to represent the Sidewinder fault in the refined model area had cells oriented corner to corner, without any overlap. This represents approximately two percent of the overall fault length represented in the refined model area. Brown and Caldwell has corrected the fault representation at these four locations to ensure that at least two model cells overlap at these locations, and re-ran the model scenarios described above to verify that this condition did not adversely affect the model results. The results of the subsequent model runs showed that the extremely small portion of the Sidewinder fault where the discontinuity occurred in the original model did not significantly affect the original model results. Model simulations completed after correction of the cell corner to cell corner condition are reflected on the revised Figure 9-2 (Attachment 1) and Figures 2-1a through 2-8a (Attachment 2).

The Bedrock Oxide Zone is an extensively fractured mass of granodiorite and quartzmonzonite. The fracturing is the result of regional scale extensional tectonic stresses that effectively pulled the rock mass apart, creating a series of faults and related fracturing throughout the rock mass. The difference between the observed faults and other fracturing is the noted evidence of displacement (i.e., slickensides, fault gouge, or observable offset). Fractures that do not show evidence of displacement are not logged as faults, while fractures that show evidence of displacement are logged as faults. Consequently, the mapped faults consist of fractures that have exhibited evidence of displacement with no regard to the degree and scale of fracturing.

The location of the plane of displacement shifts over time with changing tectonic stresses, resulting in an irregular and discontinuous fault plane at each principal shear zone. The observed faults do not exhibit discrete fault planes as inferred on cross sections prepared to accompany both APP and UIC permit application materials. Rather, the faults are characterized as fault zones consisting of numerous shear planes flanked by extensive related fracturing, which combined range in width from a few feet to several hundred feet on either side of the principal shear zone.

The shifting tectonic stresses affecting the rock mass beneath the FCP property have resulted in two significant and continuous faults (Sidewinder and Party Line), and numerous smaller, discontinuous faults which occur sub-parallel to the larger faults. The Sidewinder fault is the only significant and continuous fault that transects the PTF well field.

Based on one aquifer test conducted adjacent to the Party Line fault in 1995, it has been inferred that hydraulic conductivity adjacent and parallel to, the larger faults is greater than that observed in the remainder of the fractured rock mass, and that hydraulic conductivity perpendicular to the faults is lower than the surrounding rock mass. Other than this single aquifer test, aquifer characterization studies conducted at the FCP site made no attempt to segregate and characterize hydrologic properties of the numerous smaller and discontinuous faults and shear zones in relation to the surrounding highly fractured rock. The numerous small faults are too small and pervasive to individually characterize within the much larger and fully encompassing fractured bedrock framework.

Aquifer tests conducted at the FCP site generated data describing bulk rock hydrologic properties. All aquifer tests conducted in the Bedrock Oxide Zone demonstrate that the bedrock is so extensively fractured that the hydrologic properties are similar to an equivalent porous media. The many discontinuous small faults and shear zones have been characterized within the framework of the bulk aquifer properties developed from aquifer tests, including those conducted in the vicinity of the PTF well field. Review of core logs from core holes drilled within the footprint of the PTF well field show that the discontinuous evidence of displacement associated with the Rattlesnake and Thrasher faults is distributed over a relatively wide shear zone that spans nearly the entire distance between the two faults and the distance between these faults and the Sidewinder fault. The combined data generated from bulk properties aquifer tests, and the core logs suggests that the Bedrock Oxide Unit will behave as an equivalent porous media rather than a fault controlled hydrologic system. Therefore, small faults and shear zones, identified by evidence of displacement, were not simulated discretely within the highly fractured rock mass of the Bedrock Oxide Unit in the FCP groundwater model. Rather, the rock mass was assigned bulk hydrologic properties consistent with hydrologic data generated for the fractured rock mass, including small faults like the Rattlesnake and Thrasher faults.

8. <u>*Native Fluid Displacement*</u>*: The response is generally acceptable except that the discussion of vertical migration of lixiviant is somewhat inconsistent with the illustrations in Figures 9-1 and 9-2. The discussion on page 15 states that injected fluid is simulated to migrate upward approximately 40 feet into the exclusion zone and approximately 54 feet into the lower basin fill unit (LBFU), but no migration into the LBFU is shown in Figure 9-2.*

   Please explain why no migration is shown to occur into LBFU in the westward view in Figure 9-1 but does occur in the northward view of the PTF.

   In addition, the PTF well field is described as an area approximately 200 feet by 200 feet in size, but appears to be significantly larger (approximately 420 by 470 feet) on the figures that show the PTF well field area, notably Figures 12-, 18-1, 8-1, and others.

   If the well field dimensions are defined as the distance between the outer recovery wells, which apparently is approximately 200 by 200 feet, please clarify this definition of the well field area. All references to a 200 by 200-foot well field area should also be corrected in the application. This comment also applies to the discussion of the 500-foot AOR in Comment 1 above, and its effect on the size of the AOR and the wells and coreholes that may require corrective action.

Response to Comment 8

A revised version of Figure 9-1 is included in Attachment 1. Figure 9-1 was revised to show the limits of the PTF well field as defined above in the response to Comment 1. A revised version of Figure 9-2 is also included in Attachment 1. Figure 9-2 has been revised to reflect the assumed continuous nature of the Sidewinder fault as described above in response to Comment 7.

The text describing Figures 9-1 and 9-2 on Page 15, of *Response to Request for Information dated July 20, 2012 Class III Underground Injection Control (UIC) Well Permit Application Curis Resources (Arizona) Inc*. dated September 10, 2012, is incorrect. Both Figures 9-1 and 9-2 show migration of injected fluid into the exclusion zone at reduced concentrations, but neither figure shows migration of injected fluid into the LBFU. The revised paragragh is included below with corrections shown in **bold type face**.

> "Figures 9-1 and Figure 9-2 provide cross-sectional views of the extent of vertical migration of injected fluid under steady state injection and recovery conditions at the end of a 14-month period of operations. As shown on Figure 9-1, which represents a west-facing cross-sectional view, injected fluid migrates upward approximately 40 feet into the exclusion zone after 14 months of operating conditions, and does not reach the LBFU along this transect. Figure 9-2 provides a north-facing cross sectional view of the extent of vertical migration at the end of PTF operations. Along this west-to-east transect, injected fluid is simulated to migrate upwards approximately 40 feet into the exclusion zone **and does not reach the LBFU along this transect** ~~and approximately 54 feet into the LBFU, within a very limited lateral extent~~. In summary, model results indicate that mounding of injected fluid is limited to the 40-foot thick exclusion zone, but trace concentrations of injected fluid occur in the LBFU above the injection area as a result of dispersive effects."

An explanation of the PTF well field dimensions and the corresponding AOR is included in the response to Comment 1. Additionally, Figures 18-1, 8-1, and 12-1 have been revised to show the PTF Well Field boundary as described in the response to Comment 1 and are provided in Attachment 1. As described in the response to Comment 1, the PTF well field boundary shown on figures submitted to ADEQ represented an administrative boundary rather than the boundary of infrastructure with the potential to induce hydrologic influence in the subsurface. That administrative boundary included surface features such as roads and pipelines that will not exert hydrologic influence in the subsurface. The correct dimensions of the PTF well field, as defined by the physical installation of the outermost wells in that well field, include an area that measures 200-feet by 200-feet, and excludes surface infrastructure that does not have the potential to exert hydrologic influence in the subsurface.

ATTACHMENT O, PLANS FOR WELL FAILURES (CONTINGENCY PLANS)

9. *Demonstrating Mechanical Integrity: Regarding demonstration of Part II mechanical integrity, the volume of cement used to completely fill the annulus does not by itself demonstrate Part II mechanical integrity, as implied in the response to this comment in paragraph 1 on page 19. It also depends on the results of the cement bond log (CBL) and/or a temperature and/or RTS if the CBL is inconclusive, as stated in subsequent paragraphs on page 20.*

   Please amend paragraph 1 to remove or revise the last sentence to clarify that calculated cement volumes do not satisfy Part II requirements without a CBL and/or other logs that demonstrate mechanical integrity in the annulus of Class III wells. Paragraph 2 should be edited to state "If the cement bond and variable density log responses show adequate bonding over an acceptable interval, the Part II mechanical integrity test will have been demonstrated."

The percent bond index by itself is not necessarily indicative of adequate bonding of the cement to the casing and the borehole, and its application in PVC and FRP casing is questionable. The CBL evaluation and final determination of mechanical integrity will be subject to EPA review and approval.

Response to Comment 9

In response to Comment 9, Section O.3.1.2 has been revised and is included in its entirety below. Revised text is shown in **bold type face**.

O.3.1.2 Demonstrating Mechanical Integrity: Part II

Part II.E.2(a) - Part II of the UIC Permit addresses the requirements of 40 CFR 146.8(a)(2): mechanical integrity testing relating to the detection of significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

Curis Arizona will comply with the methods for demonstrating Part II mechanical integrity as presented below:

Part II.E.2(a) – Well Operation, Mechanical Integrity, Methods for Demonstrating Mechanical Integrity:

Part II: Mechanical Integrity *Pursuant to 40 CFR 146.8(a)(2), the permittee shall demonstrate Part II of the mechanical integrity requirement by the following methods:*

(i) Maintenance of cementing records to demonstrate adequate filling of the annulus between the borehole wall and well casing with cement, and

(ii) A cement bond log, or a temperature log and radioactive tracer survey if a cement bond is inconclusive, or

(iii) monitoring program as defined at Part II.F.6 of this permit designed to verify the absence of significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

Or, instead of (i), (ii), and (iii) above,

(iv) An alternative method, provided that the alternative method is a method listed in 40 CFR 146.8(c)(1), or is a method that has been approved by the Director as providing results equivalent to any of the methods listed in 40 CFR 146.8(c)(1).

Curis Arizona operators will conduct the Part II mechanical integrity test in the following manner, including contingency steps to be taken in the event that Part II mechanical integrity cannot be demonstrated.

1. The volume of cement used to completely fill the annulus during well construction will be recorded and compared to the volume calculated to be required to fill the annulus. **The volume will be based on a caliper log run prior to the installation of the well casing. The volume of cement used to completely fill the annulus must be equal to or greater than the calculated volume. The volume of cement is an important indicator demonstrating that the well has been constructed as designed, but alone is not a sufficient demonstration of Part II of the mechanical integrity without a cement bond log (CBL) or other confirmatory logs.**

2. A **CBL** will then be run. **If the CBL and variable density log responses show adequate bonding over an acceptable interval as determined by EPA, the Part II mechanical integrity will have been demonstrated. The CBL evaluation is subject to EPA review and approval.**

3. If the cement bond log shows **a less than acceptable** bond, the permittee may either conduct one or more additional tests as provided in the following paragraph 4 to demonstrate adequate bonding, or may have the well repaired or abandoned. If the well is repaired, it must be retested and demonstrate Part I and Part II mechanical integrity compliance before it may be placed into operation.

4. Temperature logs and/or RTS may be run to further evaluate the adequacy of a bond if the EPA determines the cement bond log is inadequate or inconclusive. If the EPA determines the temperature log and/or the RTS fail to demonstrate adequate bonding, the permittee may have the well repaired or abandoned. If the well is repaired, it must be retested and Part I and Part II mechanical integrity must be demonstrated before it may be placed into operation.

5. If EPA determines the temperature log and/or the RTS demonstrate adequate bonding, Part II of the mechanical integrity requirements will be deemed to have been fully satisfied and no further action will be required for wells that are equipped with steel casings from the ground surface to at least 40 feet below the top surface of the oxide zone. Wells equipped with PVC or FRP casing will be required to conduct quarterly monitoring of ACDs as described in the following paragraphs 6 and 7.

6 If EPA determines that a well equipped with PVC or FRP casing has passed the cement bond log, the temperature log or the RTS, a baseline of conductivity readings will be established for the annular conductivity device embedded in the well's annular space before the well is used for observation or sampling during the injection or recovery of *in-situ* solutions.

7. After a well with PVC or FRP casing is brought online, annular conductivity measurements will be collected on a quarterly basis. If a conductivity device indicates a significant increase in conductivity over the last period of measurement, the measurements will be verified. If the verification measurements verify a significant increase in conductivity, the well will be removed from service until mechanical integrity is demonstrated, as described below.
   - A Part I mechanical integrity test will be performed as described in Section O.3.1.1 above.
   - If Part I mechanical integrity is not demonstrated, the well will either be repaired and the Part I test repeated until Part I mechanical integrity is demonstrated, or the well will be abandoned.
   - If Part I mechanical integrity is demonstrated, a cement bond log will be performed to demonstrate Part II mechanical integrity.
   - If the cement bond is less than 80 percent, a temperature log or RTS may be run to determine whether the well must either be abandoned or be repaired and retested to demonstrate Part II mechanical integrity. If the EPA determines that the log and survey provide sufficient evidence of adequate bonding, Part II mechanical integrity will be deemed to have been demonstrated and the well may be returned to service with quarterly monitoring of the annular conductivity device.

In accordance with the monitoring component of the Part II mechanical integrity test, Curis Arizona will undertake the following actions to document and record Part II test activities.

1. All information regarding the cement volumetric tests required by Part II.E.2(a) – Part II(i) (as amended), will be compiled for inclusion in the quarterly report required by Part II.G.2(g) of the UIC Permit, and all annular conductivity monitoring information required by Part II.E.2(a) – Part II(ii) (as amended) of the UIC Permit will be compiled for inclusion in the next quarterly report as required by Parts II.E.2(b)(ii) and II.G.2(h) of the UIC Permit.

2. If the test results indicate that mechanical integrity has not been demonstrated, a decision will be made to abandon or repair the well, or to test mechanical integrity according to an approved alternative method.
3. If the test results with the alternative method indicate that mechanical integrity has been demonstrated, no further testing will be conducted; the test will be repeated in five years or sooner, if operational monitoring indicates a potential for well failure.
4. If the decision is to repair the well, an advance notice will be submitted to the Director as soon as possible in accordance with Part II.C.5 of the UIC Permit, the well will be retested after the repairs have been completed, and the results of the repair and retest will be included in the next quarterly report as required by Parts II.E.2(b)(ii) and II.G.2(g) and (h) of the UIC Permit.
5. If the decision is to abandon the well, a report will be submitted in accordance with Part II.E.2(c) of the UIC Permit, the abandonment and related reporting will proceed in accordance with the Plugging and Abandonment Plan, and a decision to replace the abandoned well will be made in accordance with Section O.3.2 of this attachment.

If mechanical integrity cannot be demonstrated according to the methods described above, Curis Arizona may choose to test mechanical integrity using an alternative method, subject to approval by the Director and in accordance with Part II.E.2(a) – Part I(ii) or Part II(iii) of the UIC Permit, whichever is applicable.

ATTACHMENT P, MONITORING PROGRAM

10. *Annular Conductivity Devices: Please clarify in Section P.5.3, Annular Conductivity, that wells equipped with polyvinylchloride (PVC) and FRP outer casing will not be used as injection and/or recovery wells or for maintaining hydraulic control. We understand that only observation wells and Westbay wells will be equipped with ACDs in the PVC and FRP outer casing string and that ACDs will not be installed in wells equipped with steel casing.*

Response to Comment 10

In response to Comment 10, Section P.5.3 has been revised and is included in its entirety below. Revised text is shown in **bold type face**.

Section P.5.3 Annular Conductivity

Pursuant to Part II.F.6 of the UIC Permit, Curis Arizona will establish an annular conductivity baseline for each new Class III well equipped with PVC or FRP **outer** casings before the well is used for multi-level sampling **(Westbay) or water level** observation~~, or maintaining hydraulic control~~. **Wells constructed with PVC or FRP outer casing will not be used for injection, recovery, or hydraulic control pumping. Annular conductivity devices will not be installed on wells with steel outer casings.** Additionally, Curis Arizona will perform conductivity measurements at each such well quarterly thereafter, until the affected IRZ is closed in accordance with APP and UIC Permit requirements. Significant increases in conductivity over the last period of monitoring may be an indication of ISCR fluids migrating through the annular space. Annular conductivity monitoring and associated response procedures are described in Section O.3.1.2 of Attachment O of this Application.

11. *Demonstration of Hydraulic Control: Please provide a proposed plan for an additional monitoring well in the lower 200 feet of the LBFU to the east of the PTF and above the area where Sidewinder fault and other faults meet the Oxide-LBFU contact. The recommended location is approximately 300 feet east of the outer recovery wells on the eastern perimeter of*

the PTF well field. That would be at a point where the LBFU is approximately 300 feet thick, according to the EW cross section 746167 in Attachment 13 of the May 23, 2012 response to ADEQ comments on the temporary APP application. The upper 100 feet of the LBFU in that area is above the 200-foot aquifer exemption interval in the LBFU; thus, it is required to be protected as a USDW.

Response to Comment 11

Curis Arizona herein proposes to install a supplemental monitor well (M61-LBF) located approximately 350 feet east of the PTF Well Field. The proposed location of M61-LBF is shown on Figure 11-1 (Attachment 4). Based on the SRK Geologic model, the LBFU is at its maximum thickness of 335 feet at this location, extending to 635 feet below ground surface. The aquifer exemption extends 200 feet into the LBFU; the portion of the LBFU that is above the aquifer exemption boundary is required to be protected as a USDW. This proposed well will provide a monitoring point to ensure the protection of the upper LBFU as a USDW. M61-LBF will be screened across the bottom 200 feet of the LBFU; a proposed well design is included as Figure 11-2 (Attachment 4).

12. *Additional Monitoring in the Oxide Zone: Please provide a proposed plan for additional monitoring wells: one each at the most northern, western, southern, and eastern extent of the 2 mg/L contour in Figure 14A-37, labeled "Extent of Sulfate Migration within the Oxide (All Layers) 5 Years after Closure". All of these wells should be screened in the Oxide injection zone. The northern well would be screened in the Sidewinder Fault Zone where it intersects the Oxide Zone to monitor preferential flow down gradient in the fault zone. Please confirm that coincides with the northernmost extent of the predicted sulfate migration since the Sidewinder Fault Zone is apparently aligned in that position and direction at the Oxide depth in the PTF project area. The southern well would also be placed and screened where the Sidewinder Fault Zone intersects the Oxide Zone. The distance of each well from the well field will vary from approximately 50 feet to 300 feet depending on the position of the 2 mg/L contour relative to the well field. These well locations will serve to assess the accuracy of the predictive simulations for sulfate migration five years after closure and monitor for loss of hydraulic control during PTF leaching operations.*

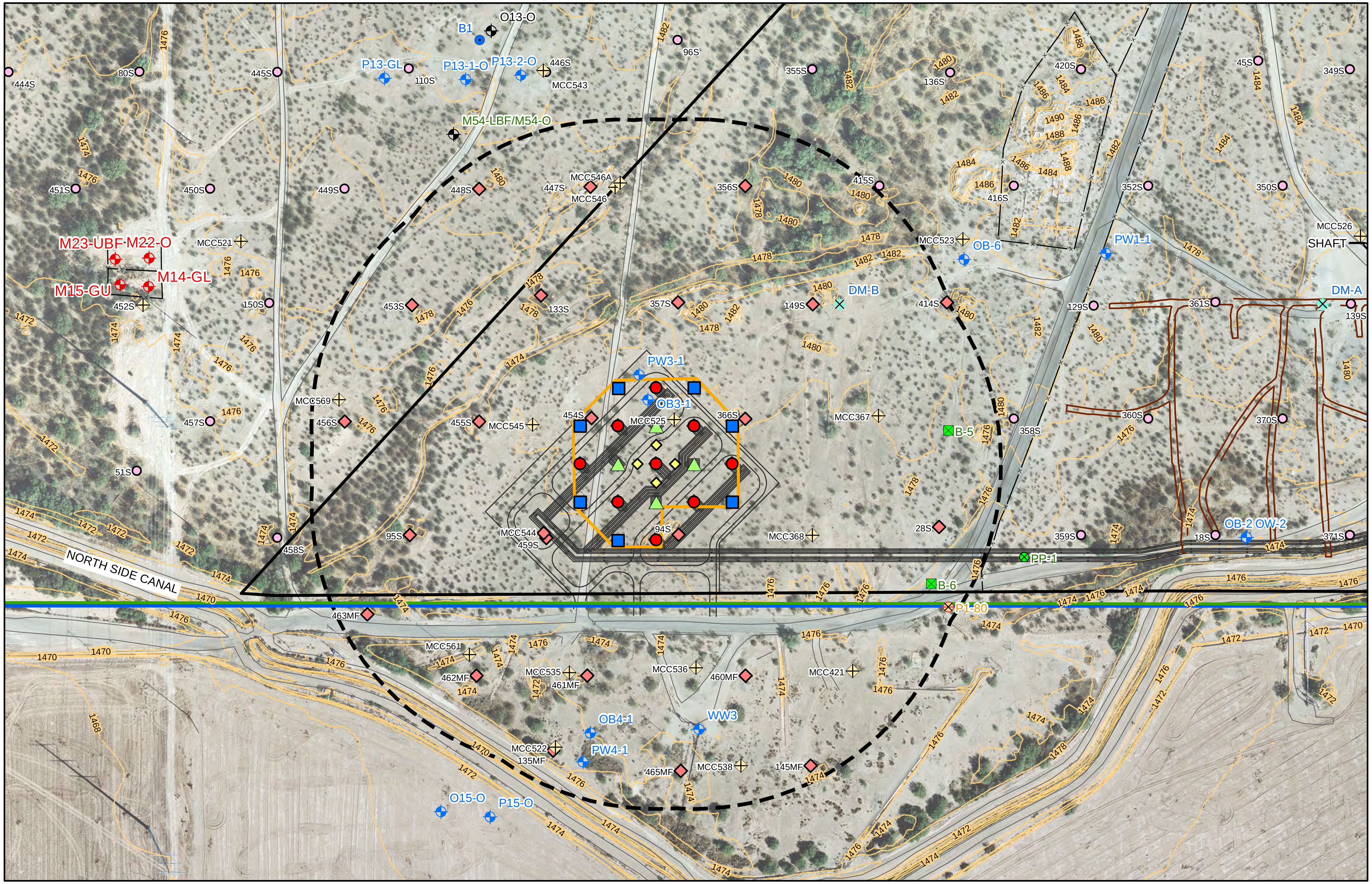
Response to Comment 12

Curis Arizona herein proposes a plan to install four supplemental monitor wells around the PTF well field. The proposed well locations are based on the most northern, eastern, southern, and western extent of the 2 mg/L contour of the "Extent of Sulfate Migration within the Oxide (All Layers) 5 Years After Closure" as shown on Figure 14A-37 of the Temporary APP application. The well locations are shown on Figure 11-1 (Attachment 4), along with the 2 mg/L sulfate migration contour.

The proposed wells will be named M57-O, M58-O, M59-O, and M60-O and will be screened from the bottom of the exclusion zone, or from 40 feet below the top of the Oxide zone, to a depth of 1,200 feet below land surface. The northern and southern wells will have screened intervals that intersect the Sidewinder fault plane as inferred in the SRK Geologic Model. Schematic diagrams of the proposed well designs showing the geologic contacts and the fault inferred fault plane intersections for these wells are included as Figures 12-1 through 12-4 (Attachment 5).

ATTACHMENT 1

Revised Figures



AERIAL SOURCE: COOPER AERIAL SURVEYS CO., OCTOBER 2010

0 100 200
SCALE IN FEET

EXPLANATION

PROPOSED PTF WELLS
- Injection
- Observation
- Recovery
- Westbay Well

POC WELLS
- POC WELL
- PROPOSED POC WELL

GEOTECHNICAL BORING
- Knight Piesold, October 2011
- Terracon 1995-1996, Abandoned

OTHER
- NON-POC WELL
- NON-POC WELL, ABANDONED
- VADOSE ZONE CHARACTERIZATION BORING
- VADOSE ZONE CHARACTERIZATION PIEZOMETER, ABANDONED
- EXPLORATION CORE HOLE
- EXPLORATION CORE HOLE TO BE ABANDONED
- EXPLORATION CORE HOLE, ABANDONED
- CONOCO UNDERGROUND MINE WORKINGS
- PROPOSED COMPONENTS OF PRODUCTION TEST FACILITY (PTF)
- TOPOGRAPHIC CONTOUR
- PTF WELL FIELD
- 500-FOOT BUFFER OF PTF WELL FIELD
- PMA BOUNDARY
- CURIS PROPERTY BOUNDARY
- STATE MINERAL LEASE BOUNDARY

HDI CURIS

Brown AND Caldwell

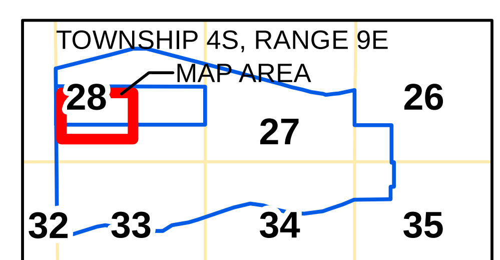


Figure Temp APP RTC(E) 18-1
WELLS AND CORE HOLES WITHIN 500 FEET OF PTF

CURIS RESOURCES (ARIZONA) INC.
FLORENCE, ARIZONA

Path(BCPhx03): P:\Hunter Dickinson\Curis GIS\MXDs\TempPermitRTC\G140753340RTC001.mxd Updated: 11/20/2012

AERIAL SOURCE: COOPER AERIAL SURVEYS CO., OCTOBER 2010

HDI CURIS

Brown AND Caldwell

0 150 300
SCALE IN FEET

EXPLANATION

POC WELLS
- POC WELL
- PROPOSED POC WELL

GEOTECHNICAL BORINGS
- KNIGHT PIESOLD, OCTOBER 2011
- TERRACON, 1995-1996

OTHER
- NON-POC WELL
- POC WELL (TO BE ABANDONED)
- NON-POC WELL, ABANDONED
- SUPPLEMENTAL MONITORING WELL

- VADOSE ZONE CHARACTERIZATION BORING
- VADOSE ZONE CHARACTERIZATION PIEZOMETER, ABANDONED
- EXPLORATION CORE HOLE
- EXPLORATION CORE HOLE TO BE ABANDONED
- EXPLORATION CORE HOLE, ABANDONED
- CONOCO UNDERGROUND MINE WORKINGS
- PROPOSED COMPONENTS OF PRODUCTION TEST FACILITY (PTF)

- TOPOGRAPHIC CONTOUR
- PTF WELL FIELD
- 500-FOOT BUFFER OF PTF WELL FIELD
- PMA BOUNDARY
- STATE MINERAL LEASE BOUNDARY
- CURIS PROPERTY BOUNDARY

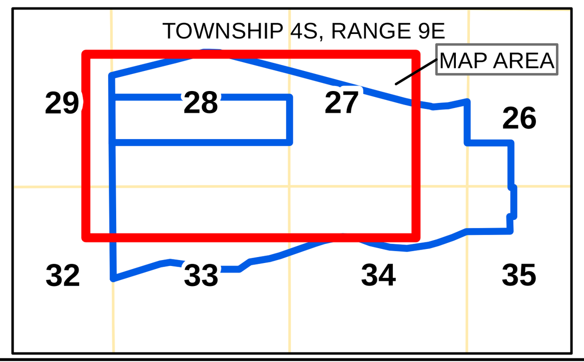
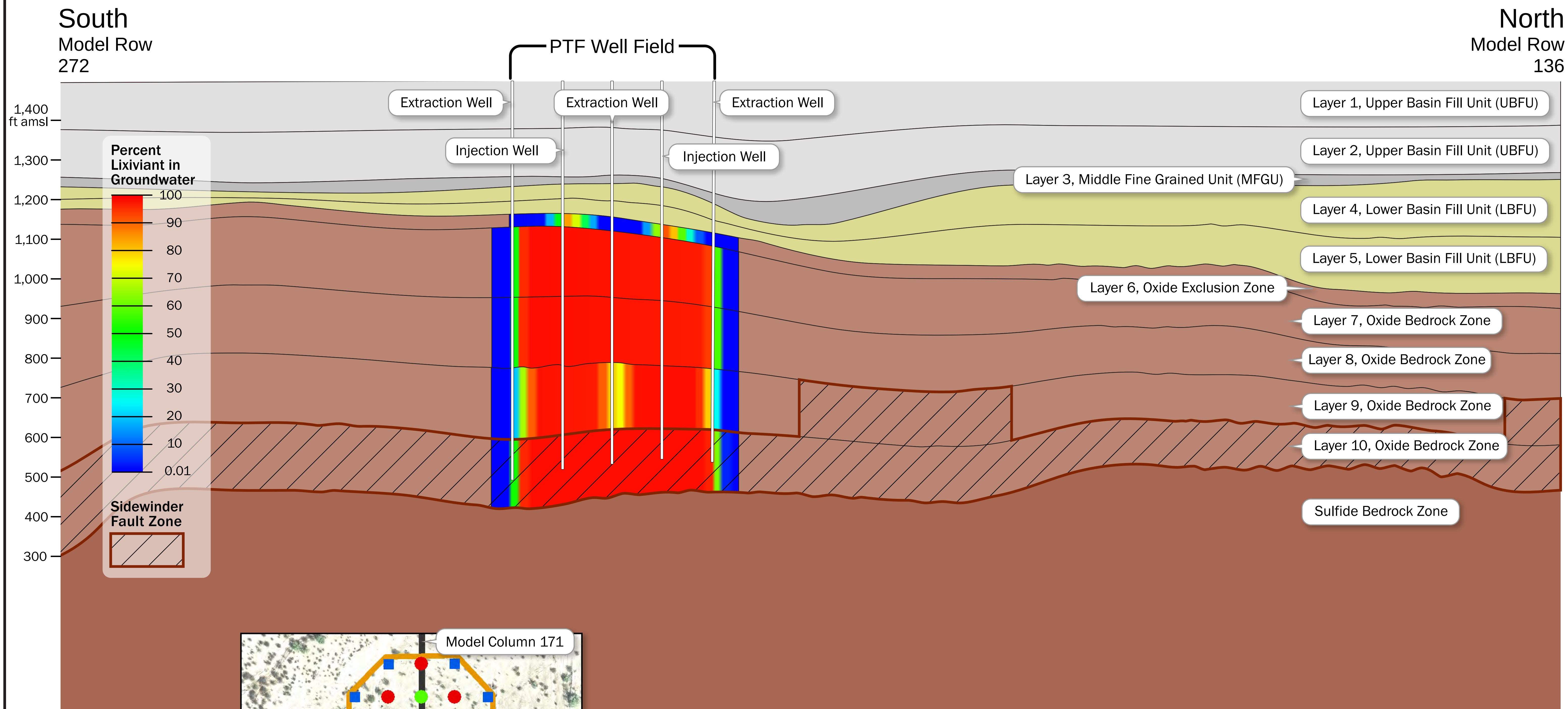
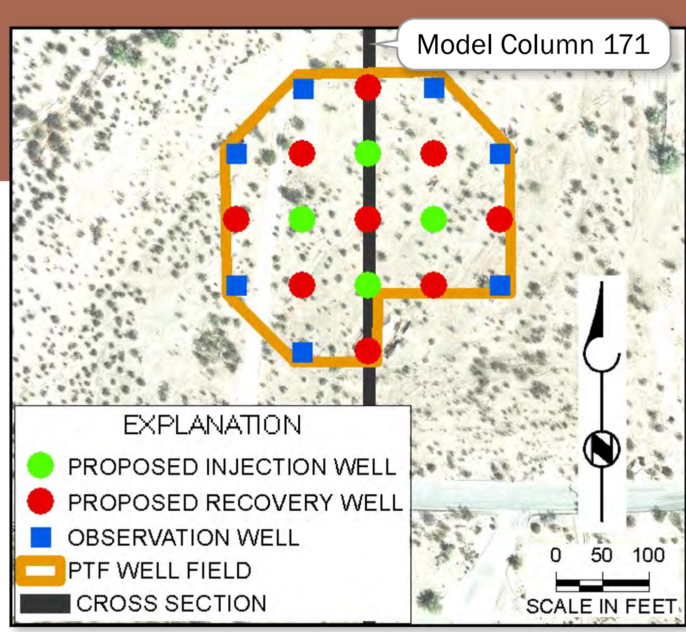


Figure 8-1 (Revised 112012)
SITE PLAN
CURIS RESOURCES (ARIZONA) INC.
FLORENCE, ARIZONA

Path(Phx): P:\Hunter Dickinson\Curis GIS\MXDs\TempPermitRTC\G140753340_001RTC.mxd Updated: 11/20/2012

Cross-Section along Model Column 171





Scenario 8 Simulation Details and Variations from Base FCP Model:

- 14 months simulation time
- 4 PTF wells injecting at 60 gpm each
- 9 PTF recovery wells pumping at 300 gpm total
- Hydrologic parameters same as base FCP Model (Table 10-1)

Brown AND Caldwell

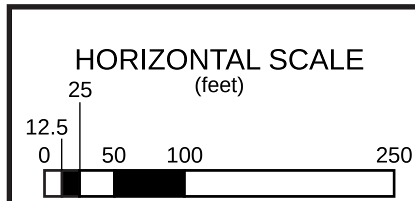
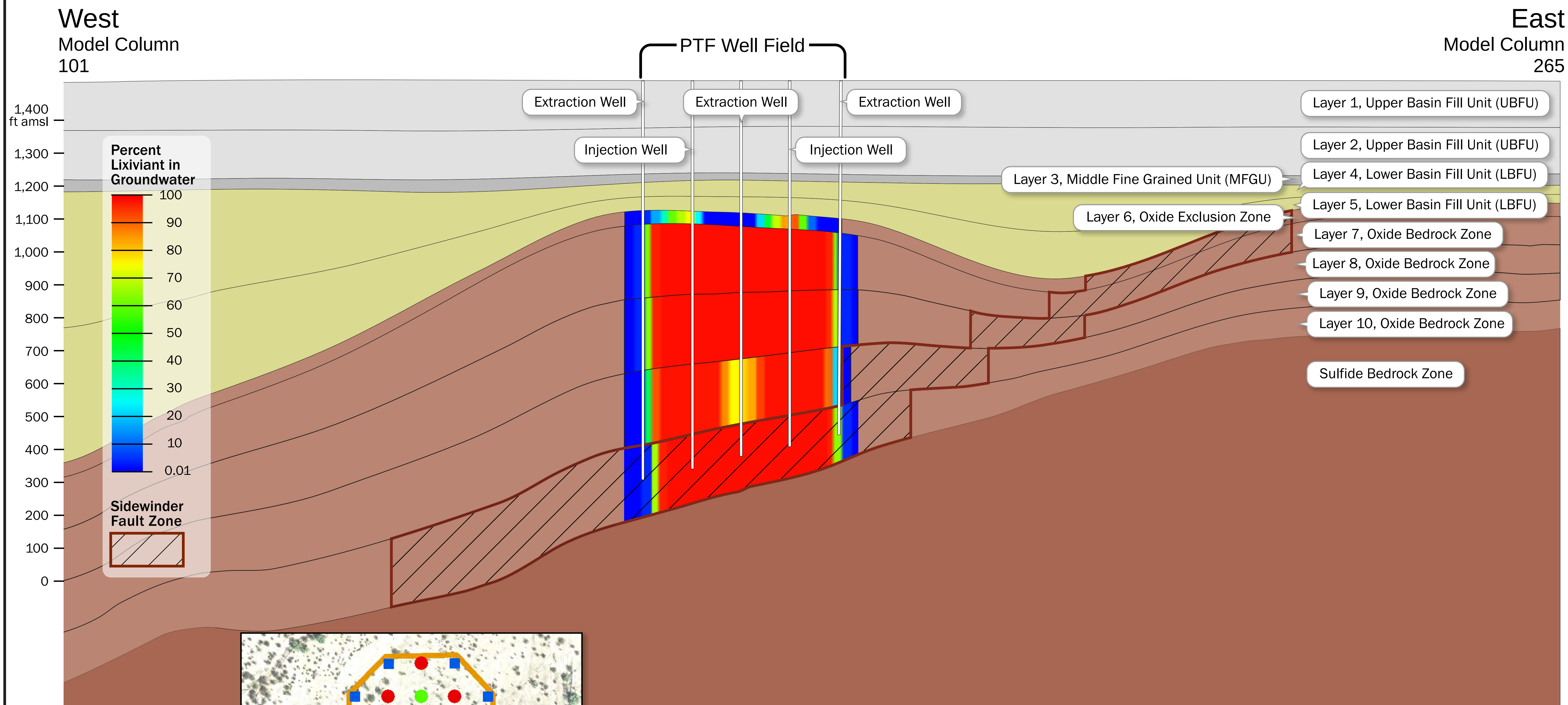
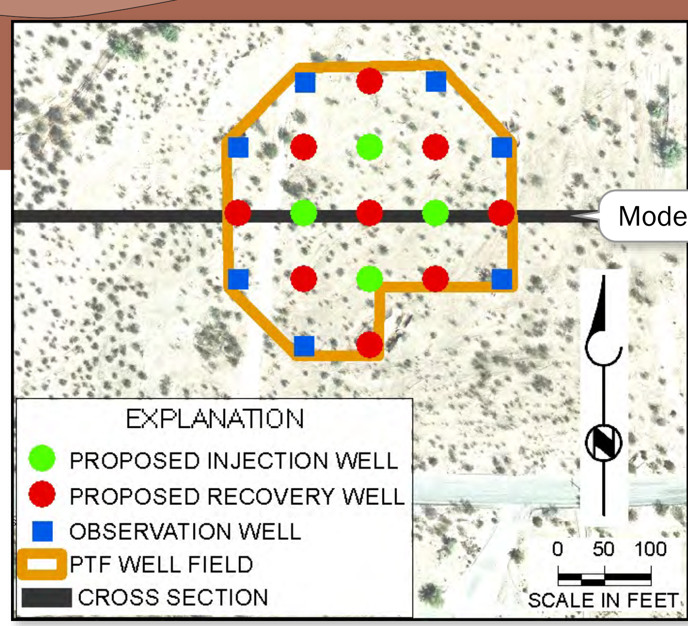


Figure 9-1 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 8
West-facing Cross Section
Florence Copper Project Groundwater Model

Cross-Section along Model Row 231





Scenario 8 Simulation Details and Variations from Base FCP Model:

- 14 months simulation time
- 4 PTF wells injecting at 60 gpm each
- 9 PTF recovery wells pumping at 300 gpm total
- Hydrologic parameters same as base FCP Model (Table 10-1)

Brown AND Caldwell

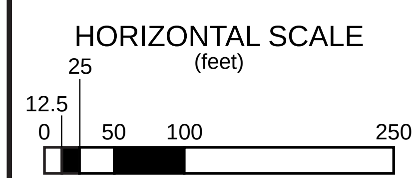
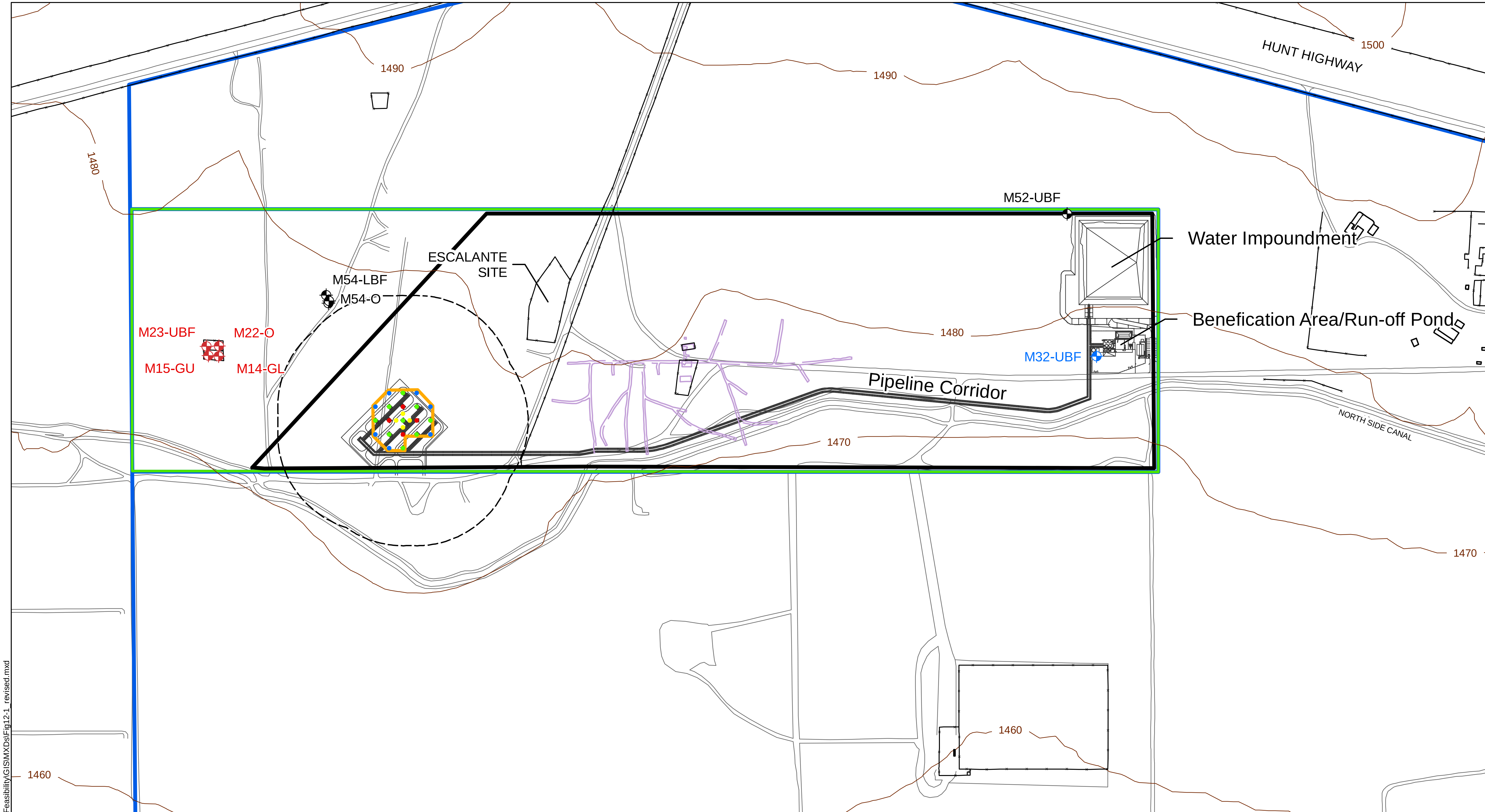


Figure 9-2 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 8
North-facing Cross Section
Florence Copper Project Groundwater Model



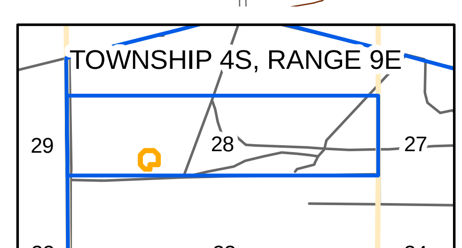
LEGEND

EXISTING POC WELL
APPROVED NEW POC WELL
POC WELL TO BE ABANDONED

PTF WELLS
INJECTION
OBSERVATION
RECOVERY
WESTBAY

SURFACE COMPONENTS OF PTF
PTF WELL FIELD
500-FOOT BUFFER OF PTF WELL FIELD
PMA BOUNDARY

STATE MINERAL LEASE BOUNDARY
CURIS PROPERTY BOUNDARY
CONOCO UNDERGROUND MINE WORKINGS
TOPOGRAPHIC CONTOUR



N
W E
S

0 210 420 840
SCALE IN FEET

HALEY & ALDRICH

CURIS RESOURCES (ARIZONA) INC.
FLORENCE, ARIZONA

EXISTING AND PROPOSED
POINT OF COMPLIANCE WELLS

HDI CURIS

SCALE: AS SHOWN
NOVEMBER 2012

FIGURE 12-1

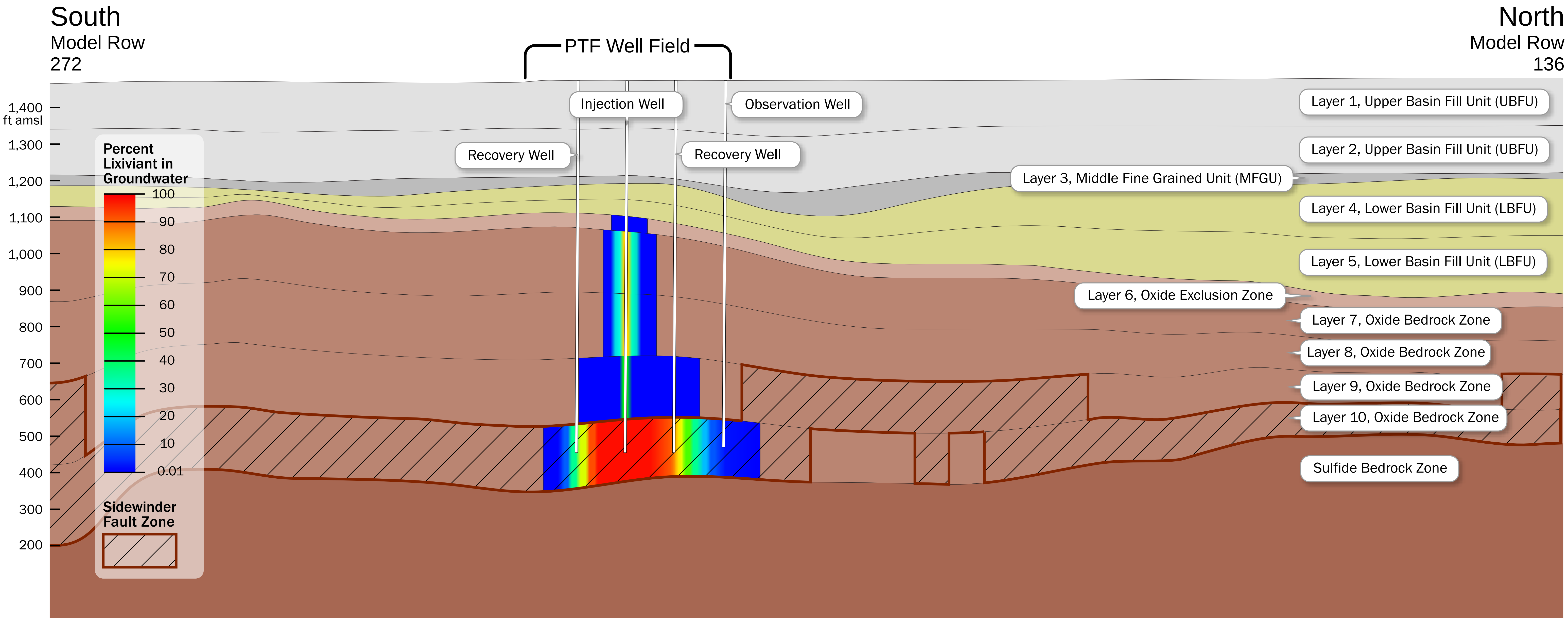
G:\Projects\Curis Resources\38706-Curis Feasibility\GIS\MXDs\Fig12-1_revised.mxd

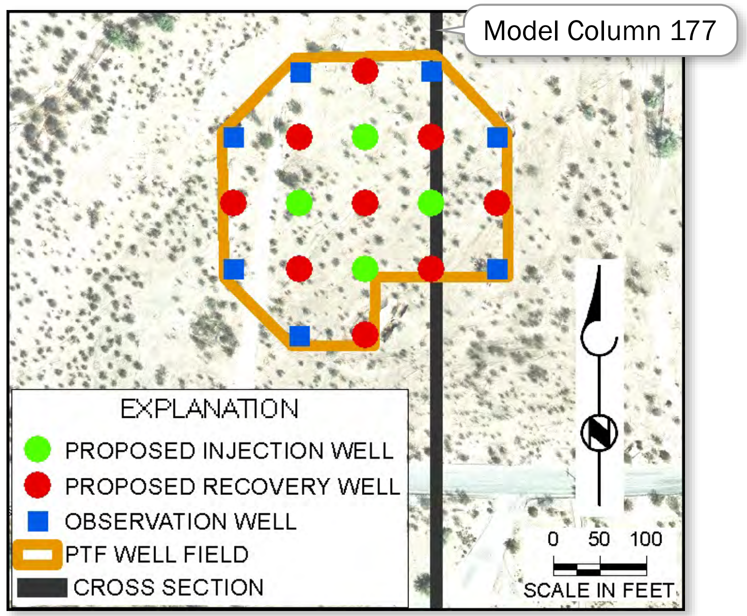
ATTACHMENT 2

NORTH-SOUTH CROSS SECTIONS

EAST-WEST CROSS SECTIONS

Cross-Section along Model Column 177





Scenario 1 Simulation Details and Variations from Base FCP Model:

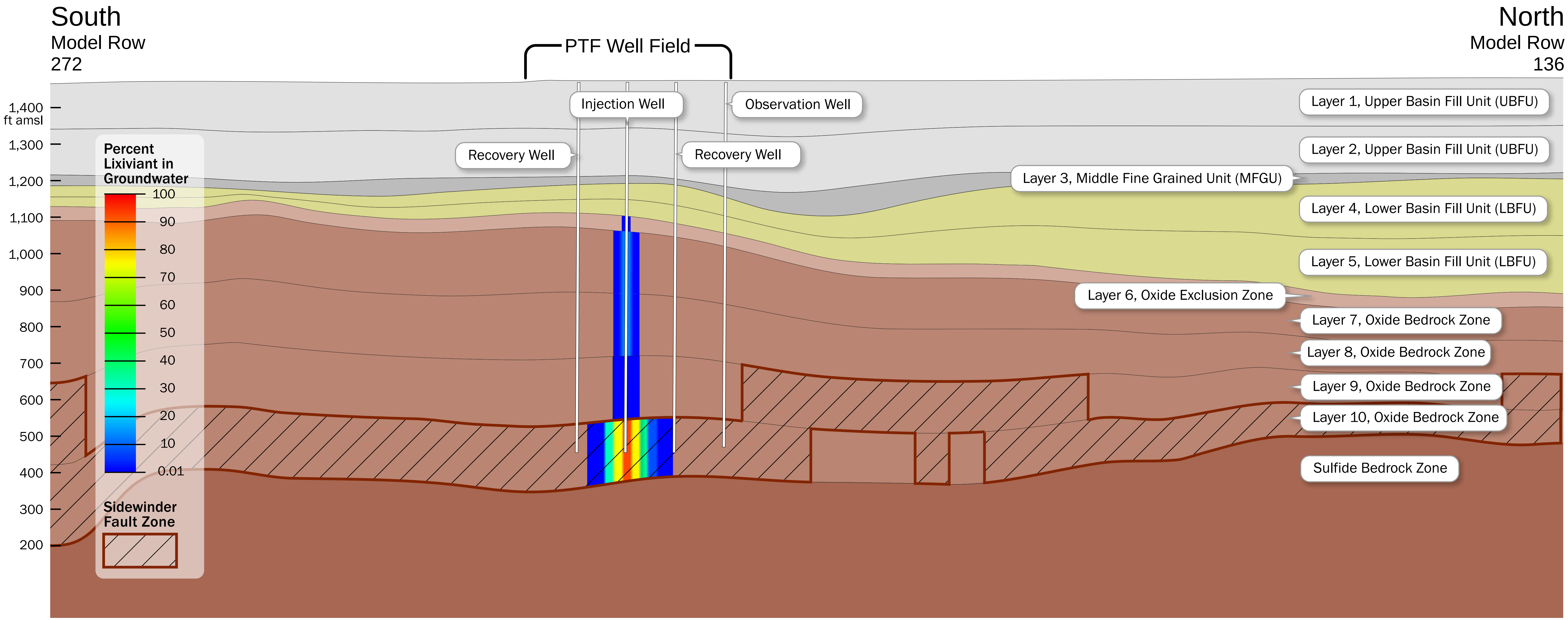
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Hydraulic conductivity of Sidewinder Fault Zone = 40 feet/day
- Porosity of Sidewinder Fault Zone = 10% (same as Base FCP Model)
- Other hydrologic parameters same as base FCP Model (Table 10-1)

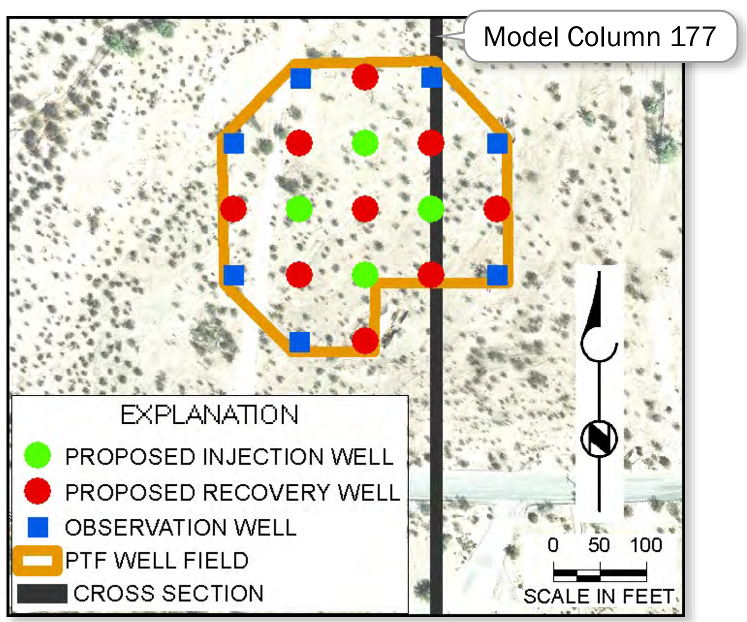
Brown AND Caldwell

HORIZONTAL SCALE (feet)
12.5 25
0 50 100 250

Figure 2-1 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 1
Florence Copper Project Groundwater Model

Cross-Section along Model Column 177





Scenario 1 Simulation Details and Variations from Base FCP Model:

- 48 hours simulation time
- One well injecting at 60 gpm, no recovery pumping
- Hydraulic conductivity of Sidewinder Fault Zone = 40 feet/day
- Porosity of Sidewinder Fault Zone = 10% (same as Base FCP Model)
- Other hydrologic parameters same as base FCP Model (Table 10-1)

Brown AND Caldwell

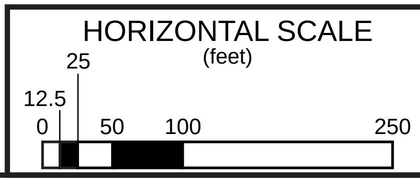
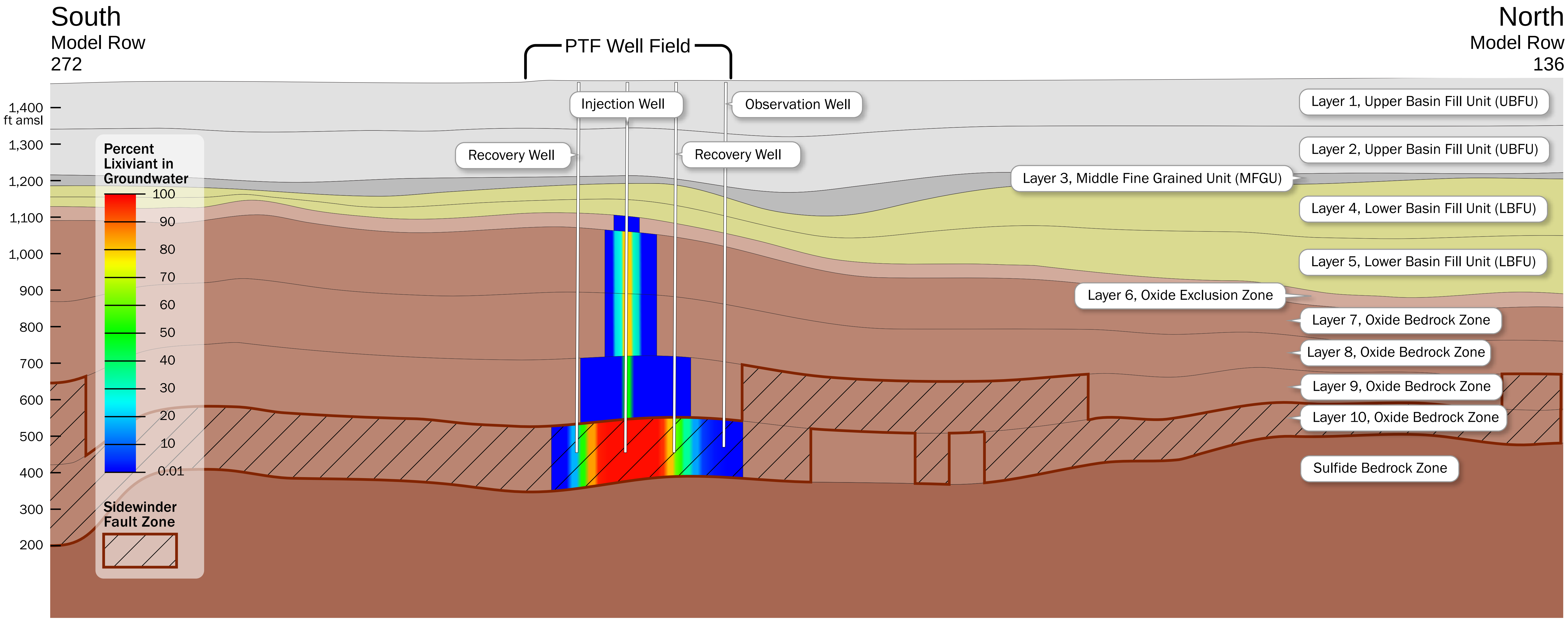
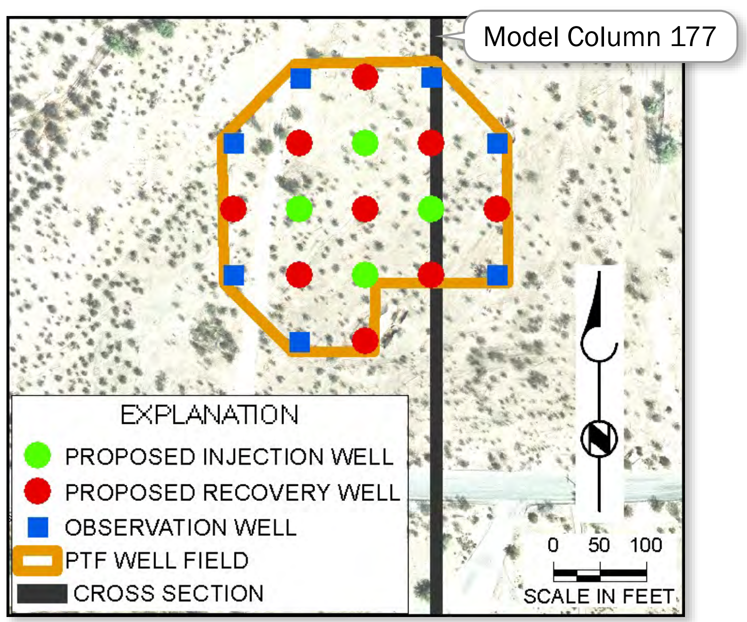


Figure 2-2 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 1
Florence Copper Project Groundwater Model

Cross-Section along Model Column 177





Scenario 2 Simulation Details and Variations from Base FCP Model:

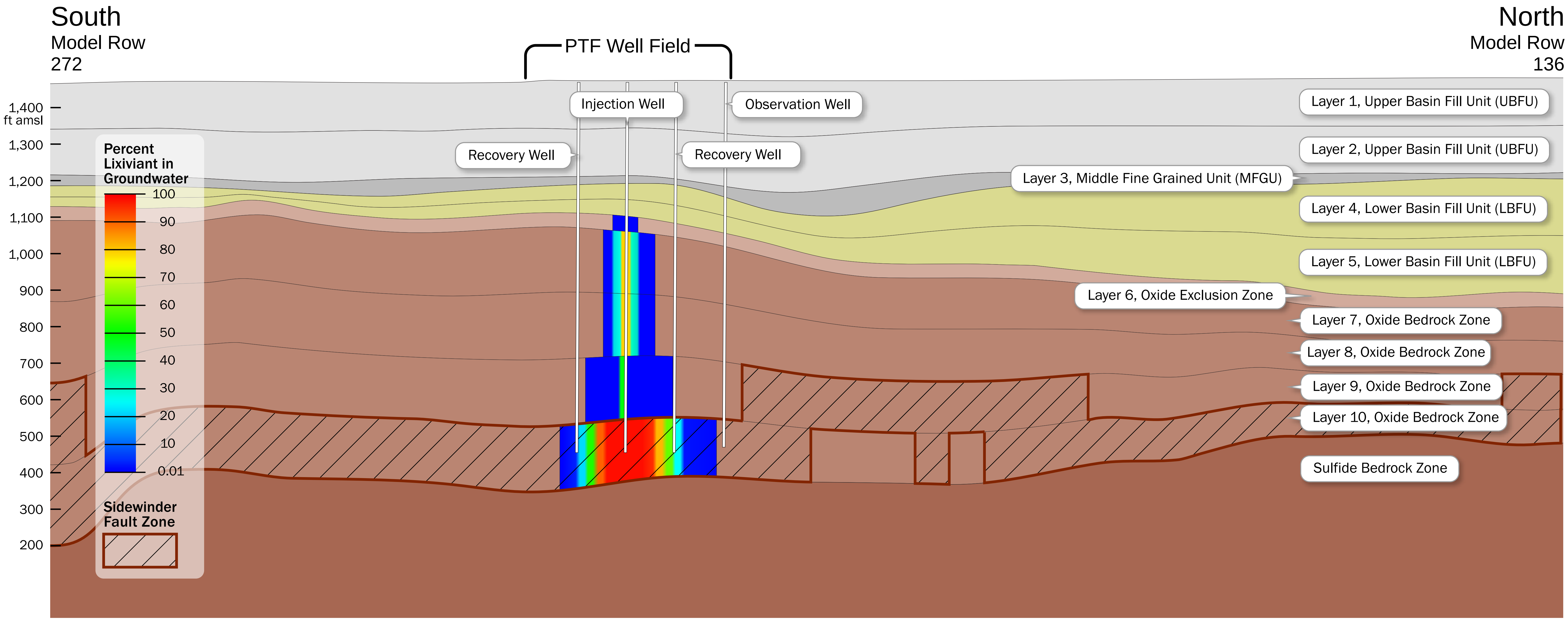
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Hydraulic conductivity of Sidewinder Fault Zone = 40 feet/day
- Porosity of Sidewinder Fault Zone = 13%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

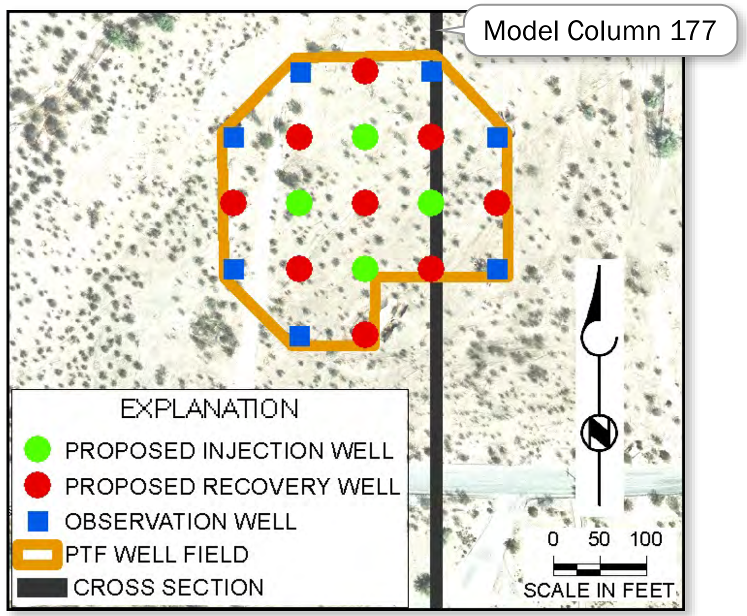
Brown AND Caldwell

HORIZONTAL SCALE
(feet)
25
12.5
0 50 100 250

Figure 2-3 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 2
Florence Copper Project Groundwater Model

Cross-Section along Model Column 177





<u>Scenario 3 Simulation Details and Variations from Base FCP Model:</u>

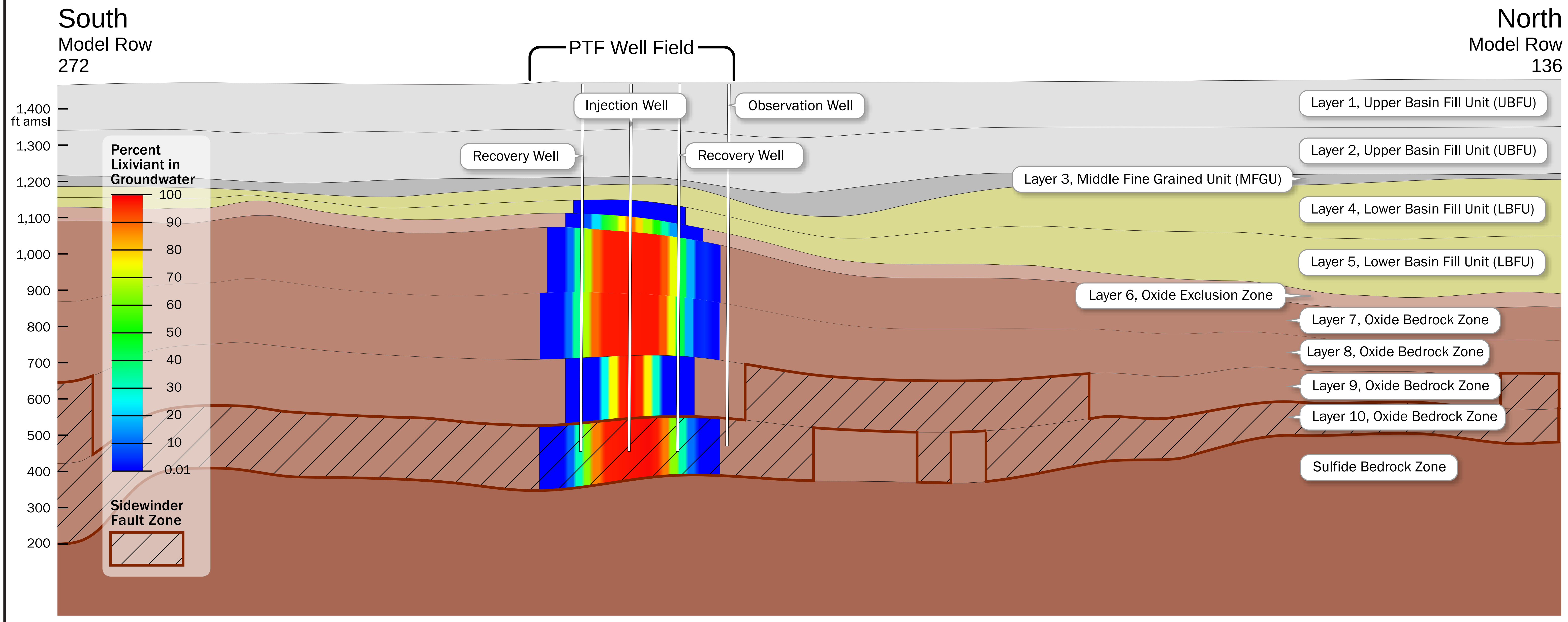
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Hydraulic conductivity of Sidewinder Fault Zone = 40 feet/day
- Porosity of Sidewinder Fault Zone = 20%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

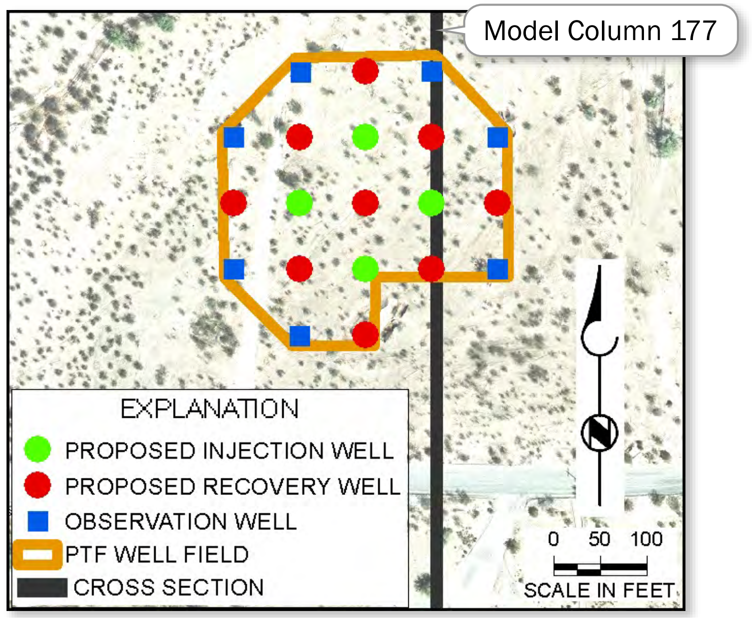
Brown AND Caldwell

HORIZONTAL SCALE
(feet)
0 12.5 25 50 100 250

Figure 2-4 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 3
Florence Copper Project Groundwater Model

Cross-Section along Model Column 177





Scenario 4 Simulation Details and Variations from Base FCP Model:

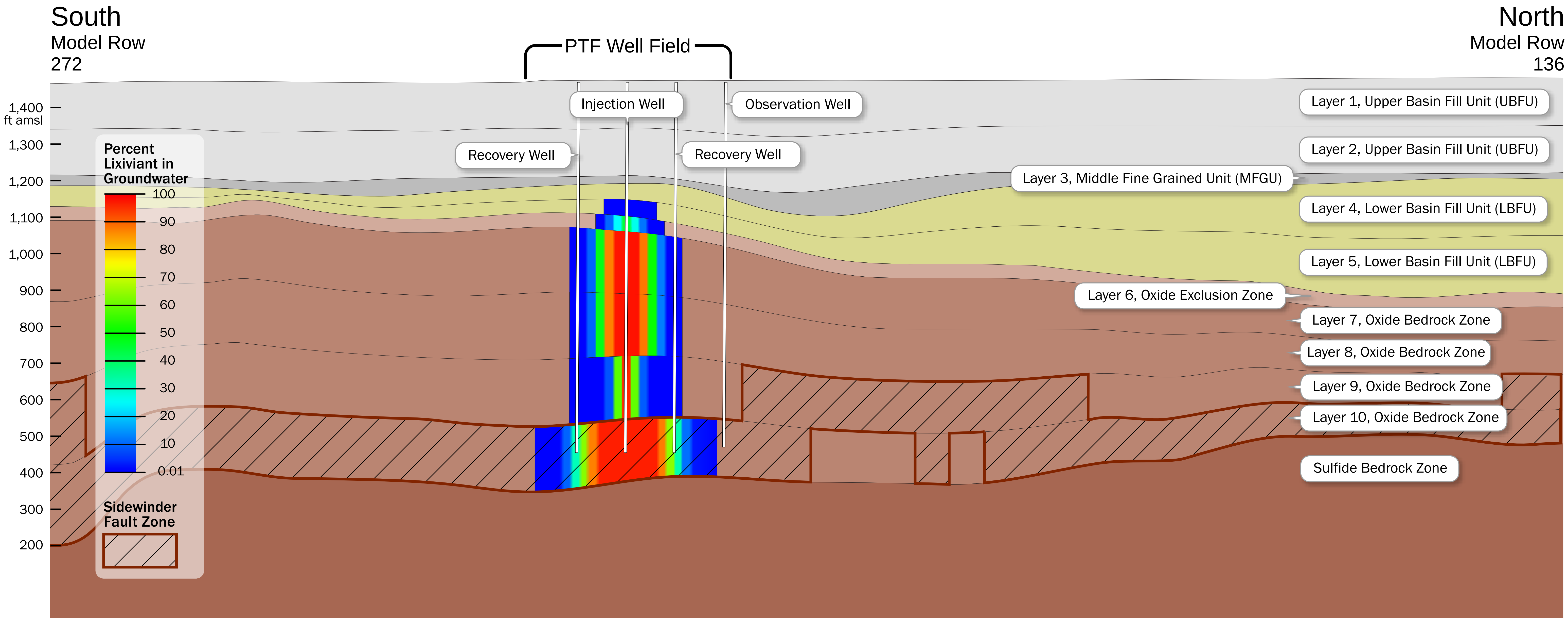
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Porosity of Oxide Layers = 2%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

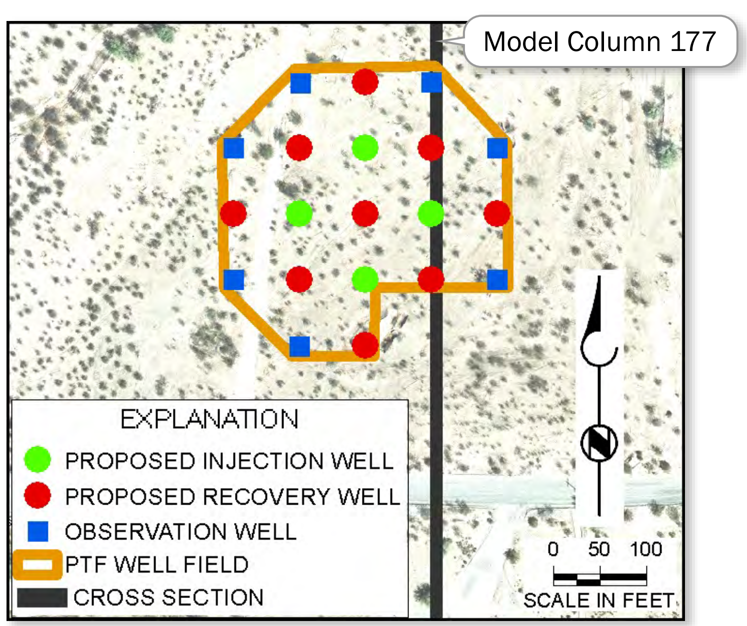
Brown AND Caldwell

HORIZONTAL SCALE
(feet)
0 12.5 25 50 100 250

Figure 2-5 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 4
Florence Copper Project Groundwater Model

Cross-Section along Model Column 177





Scenario 5 Simulation Details and Variations from Base FCP Model:

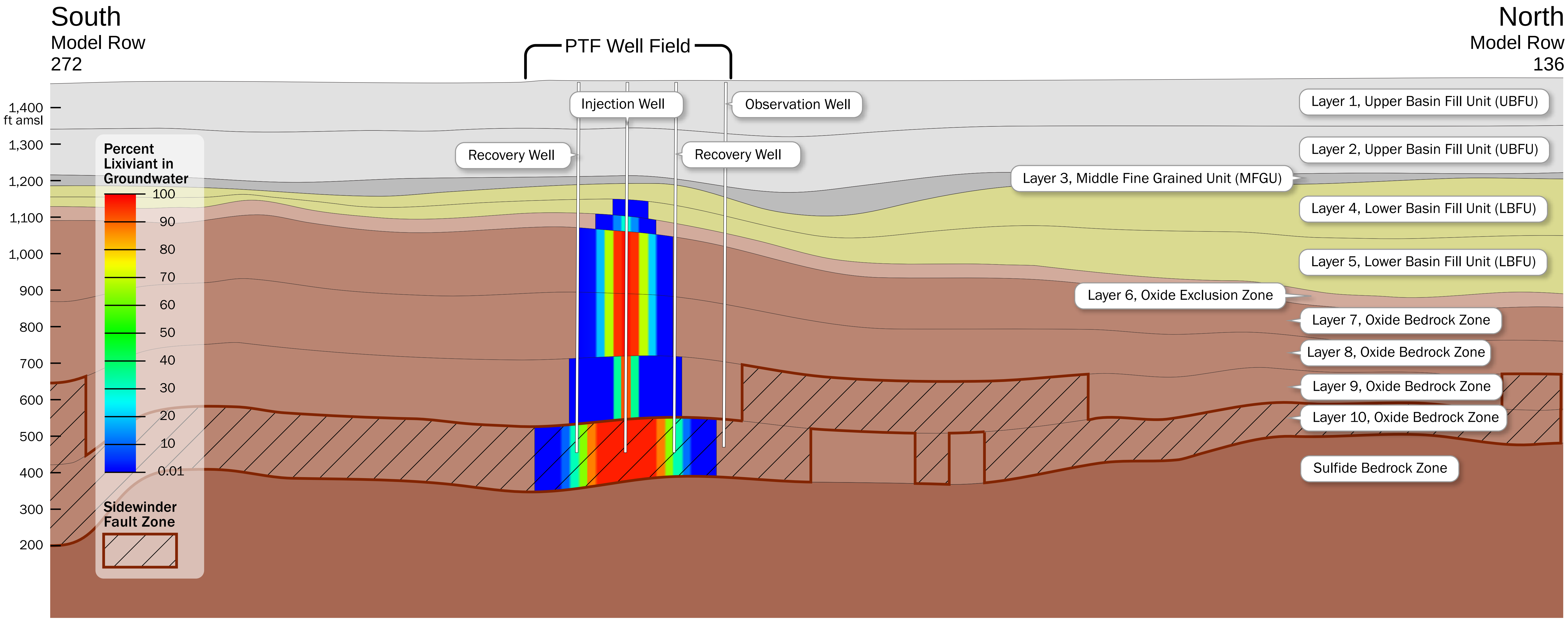
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Porosity of Oxide Layers = 8%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

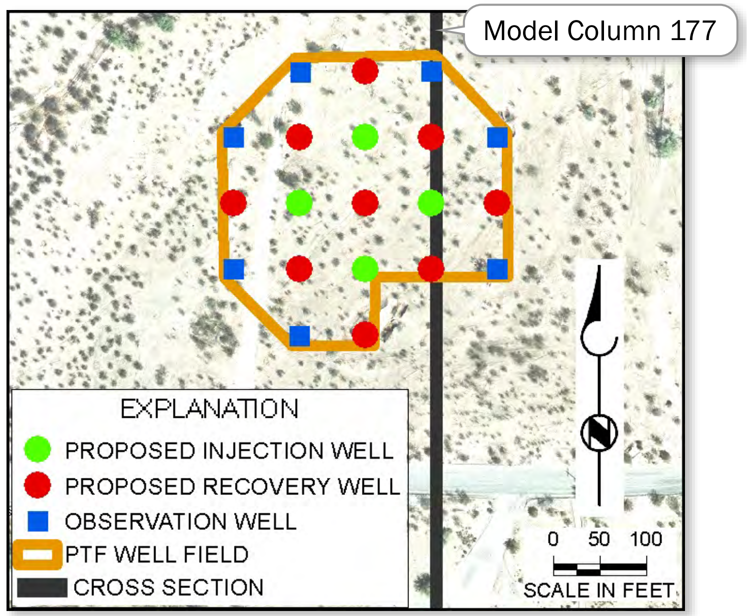
Brown AND Caldwell

HORIZONTAL SCALE
(feet)
0 12.5 25 50 100 250

Figure 2-6 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 5
Florence Copper Project Groundwater Model

Cross-Section along Model Column 177





Scenario 6 Simulation Details and Variations from Base FCP Model:

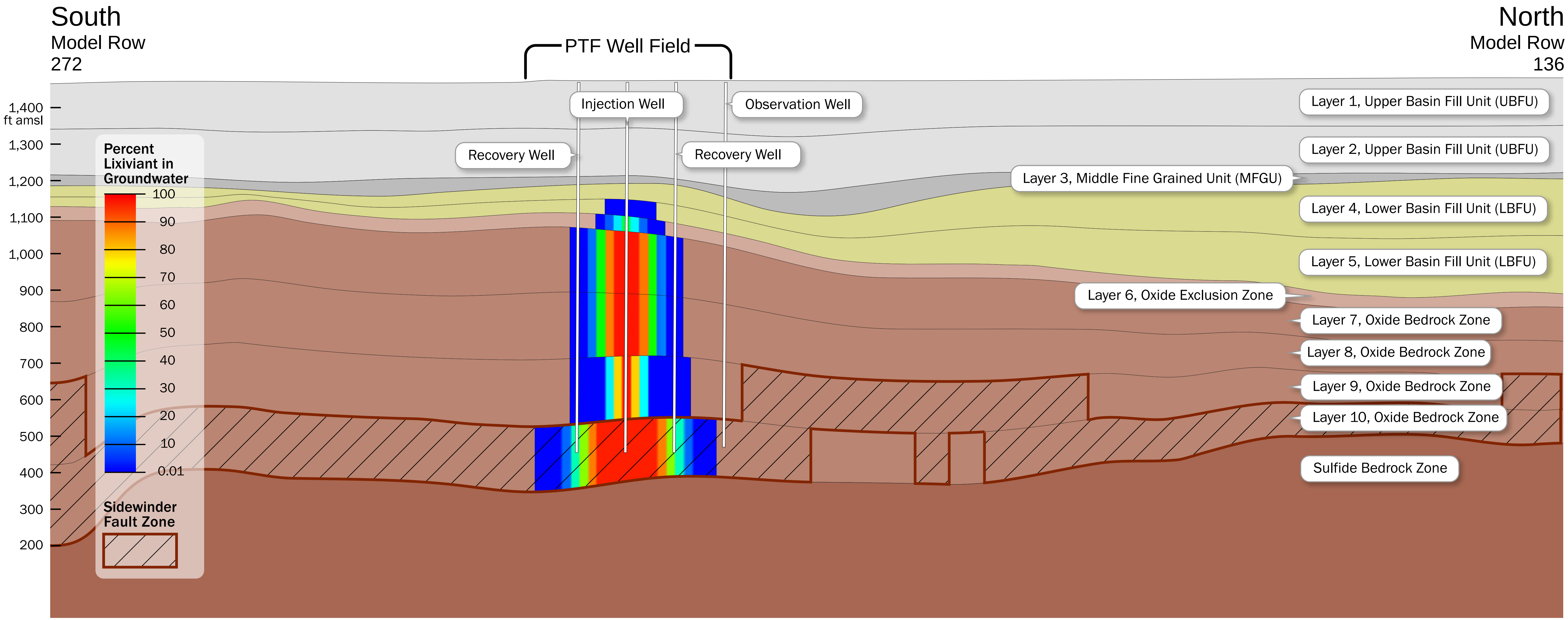
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Porosity of Oxide Layers = 13%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

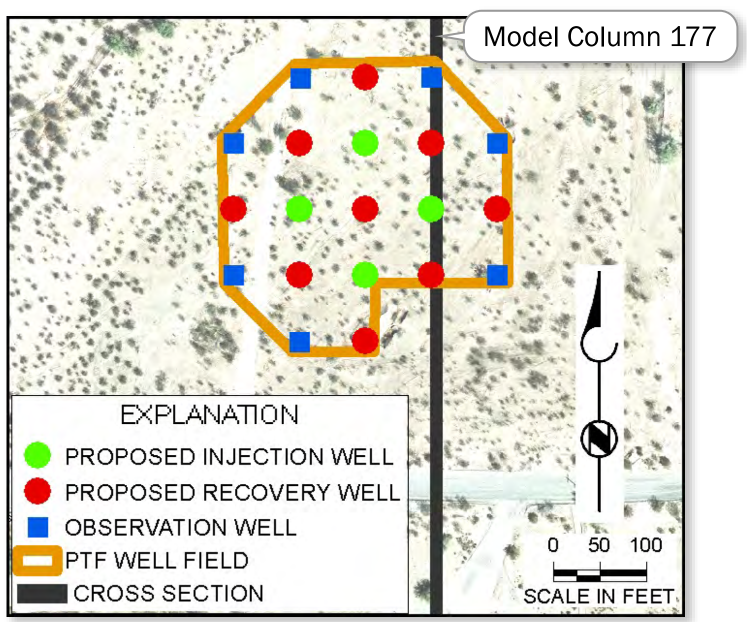
Brown AND Caldwell

HORIZONTAL SCALE
(feet)
0 12.5 25 50 100 250

Figure 2-7 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 6
Florence Copper Project Groundwater Model

Cross-Section along Model Column 177





Scenario 7 Simulation Details and Variations from Base FCP Model:

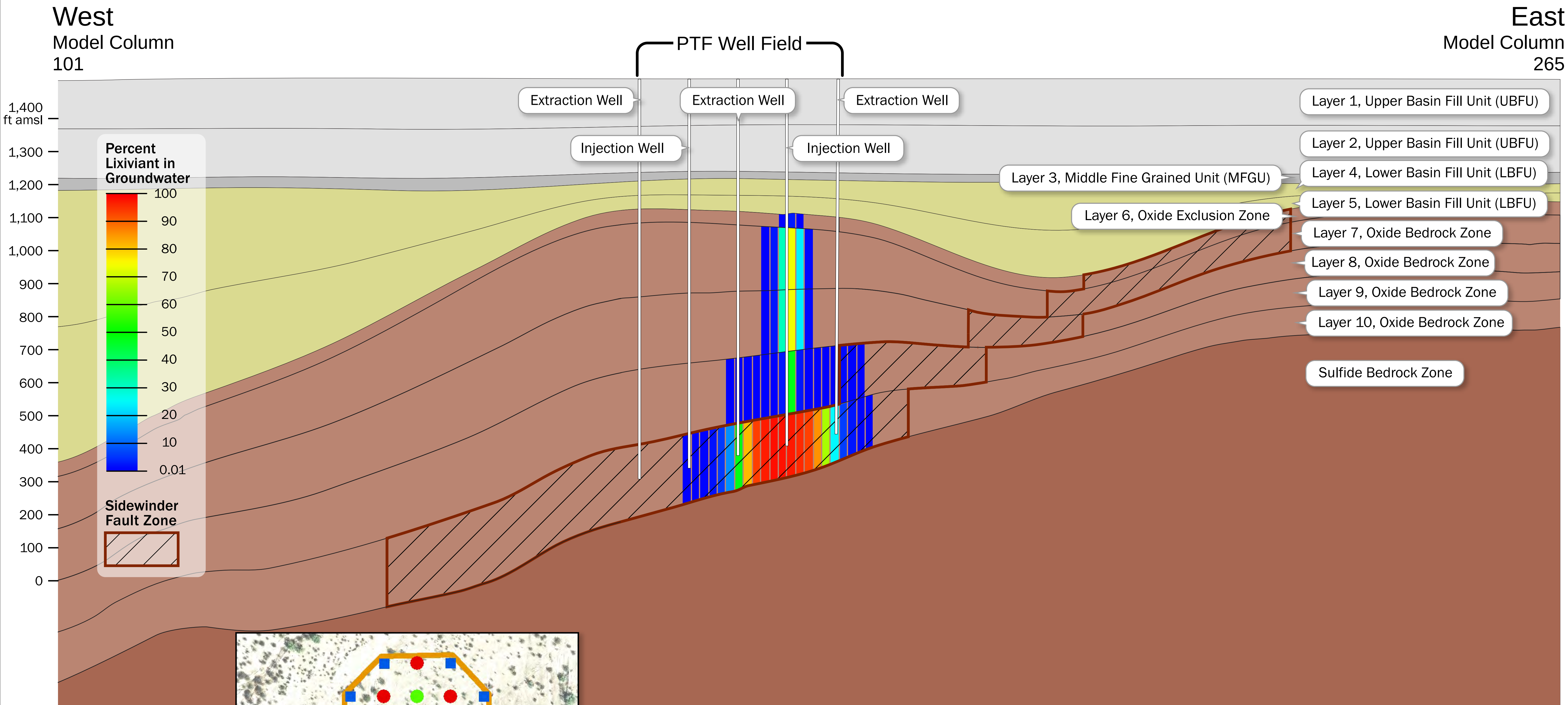
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- No confining unit in vicinity of PTF
- Hydraulic conductivity of MFGU (Layer 3) set to magnitude of LBFU
- Other hydrologic parameters same as base FCP Model (Table 10-1)

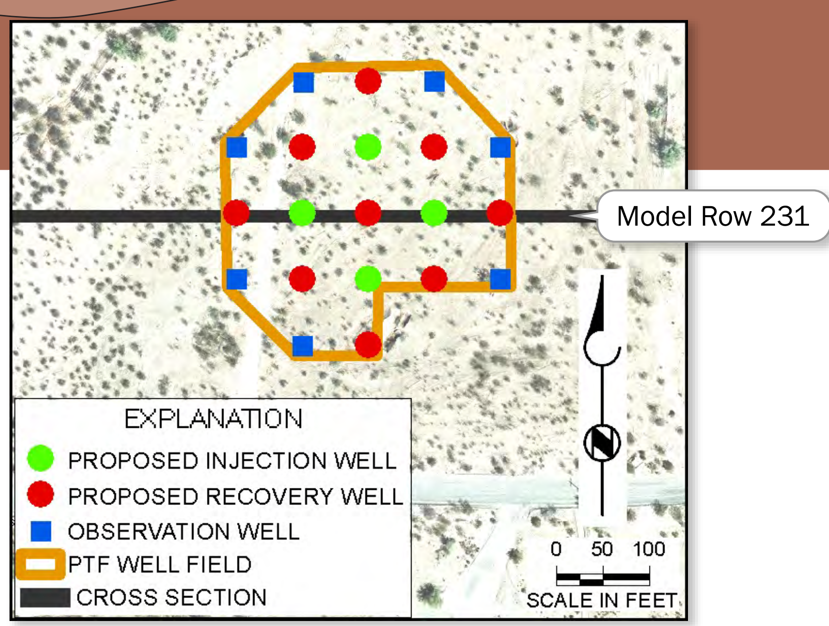
Brown AND Caldwell

HORIZONTAL SCALE
(feet)
0 12.5 25 50 100 250

Figure 2-8 (REVISED 12062012)
Model Predicted Migration of Lixiviant – Scenario 7
Florence Copper Project Groundwater Model

Cross-Section along Model Row 231





Scenario 1 Simulation Details and Variations from Base FCP Model:

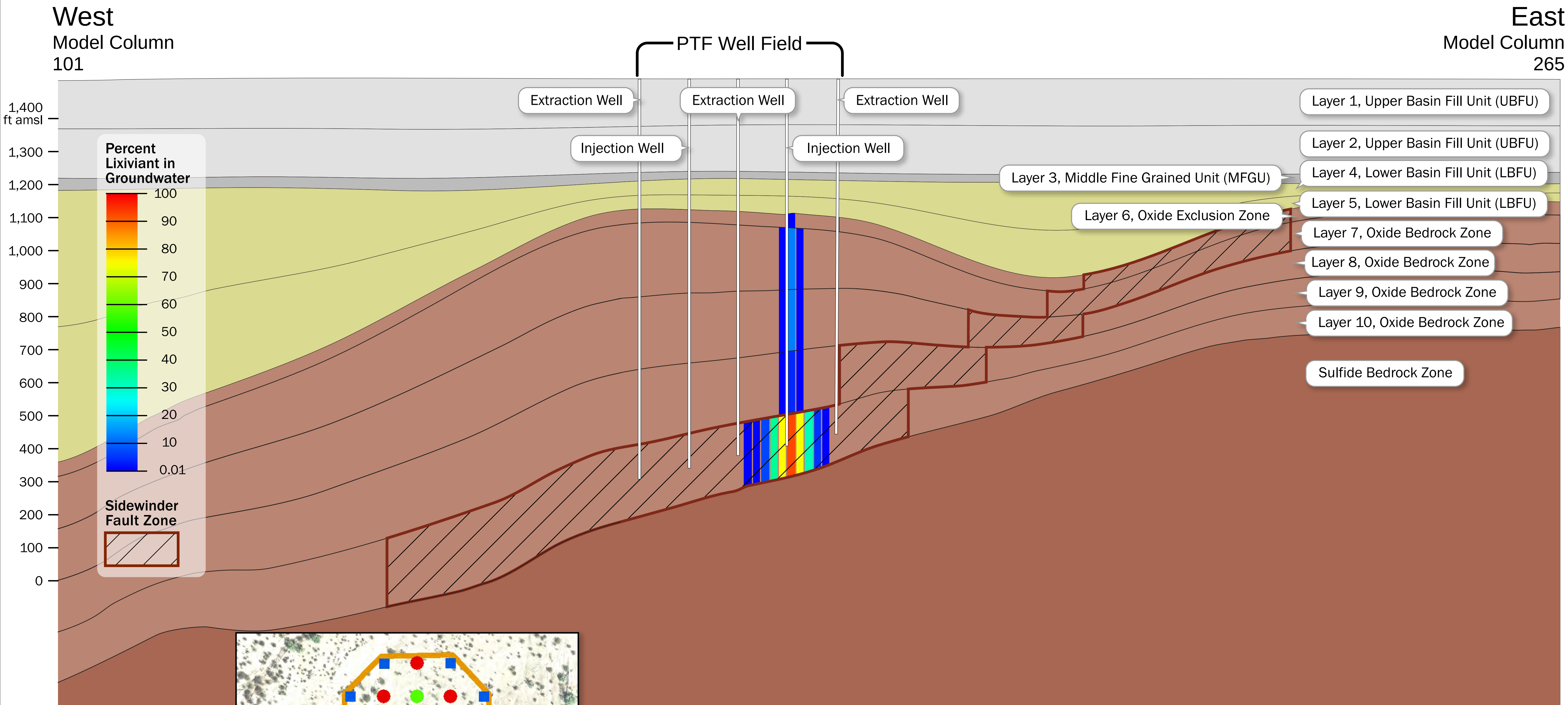
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Hydraulic conductivity of Sidewinder Fault Zone = 40 feet/day
- Porosity of Sidewinder Fault Zone = 10% (same as Base FCP Model)
- Other hydrologic parameters same as base FCP Model (Table 10-1)

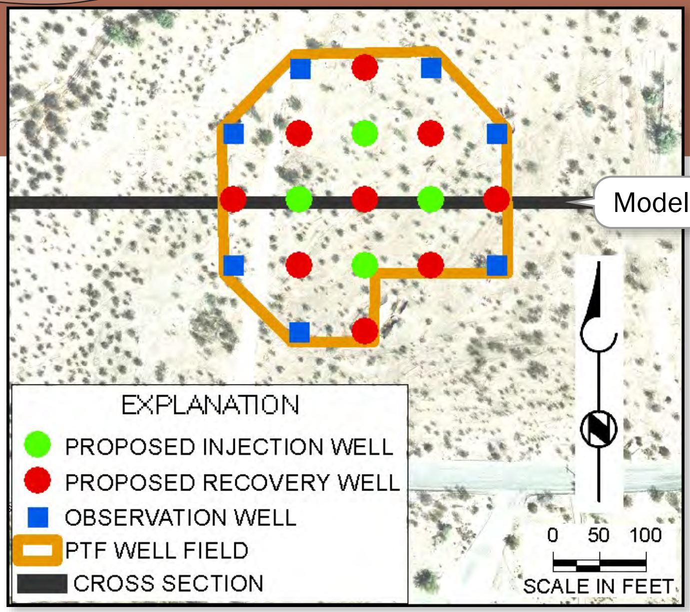
HORIZONTAL SCALE
(feet)
25
12.5
0 50 100 250

Brown AND Caldwell

Figure 2-1a
Model Predicted Migration of Lixiviant – Scenario 1
North-facing Cross Section
Florence Copper Project Groundwater Model

Cross-Section along Model Row 231





Scenario 1 Simulation Details and Variations from Base FCP Model:

- 48 hours simulation time
- One well injecting at 60 gpm, no recovery pumping
- Hydraulic conductivity of Sidewinder Fault Zone = 40 feet/day
- Porosity of Sidewinder Fault Zone = 10% (same as Base FCP Model)
- Other hydrologic parameters same as base FCP Model (Table 10-1)

Brown AND Caldwell

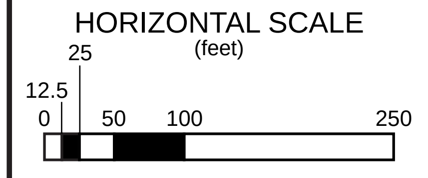
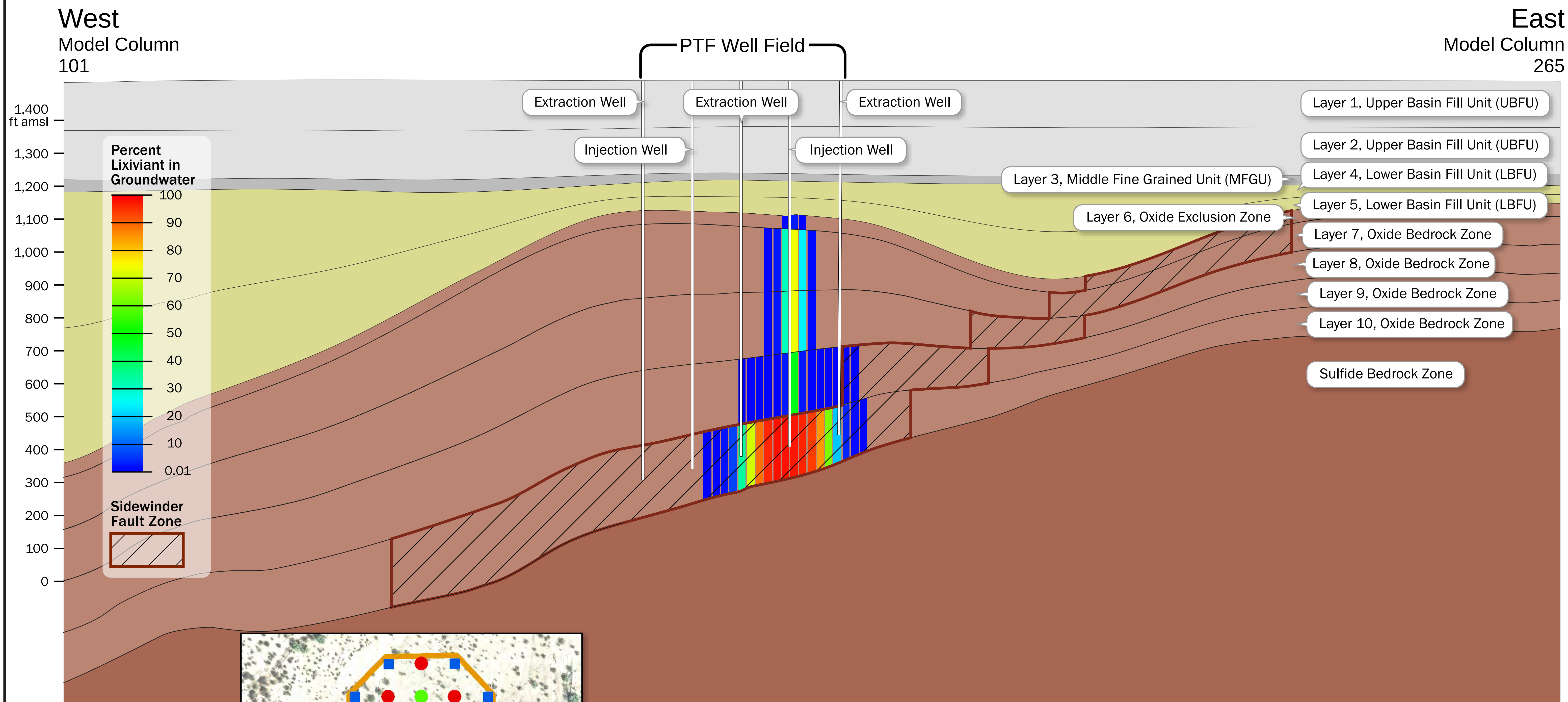
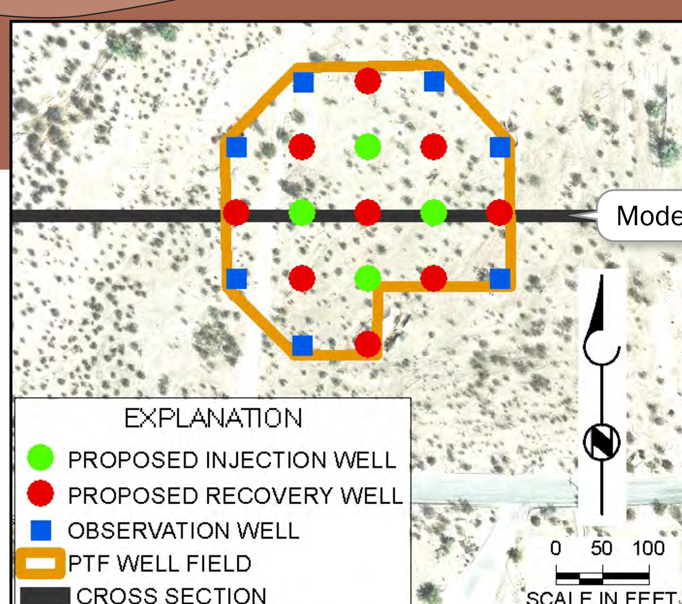


Figure 2-2a
Model Predicted Migration of Lixiviant – Scenario 1
North-facing Cross Section
Florence Copper Project Groundwater Model

Cross-Section along Model Row 231





Scenario 2 Simulation Details and Variations from Base FCP Model:

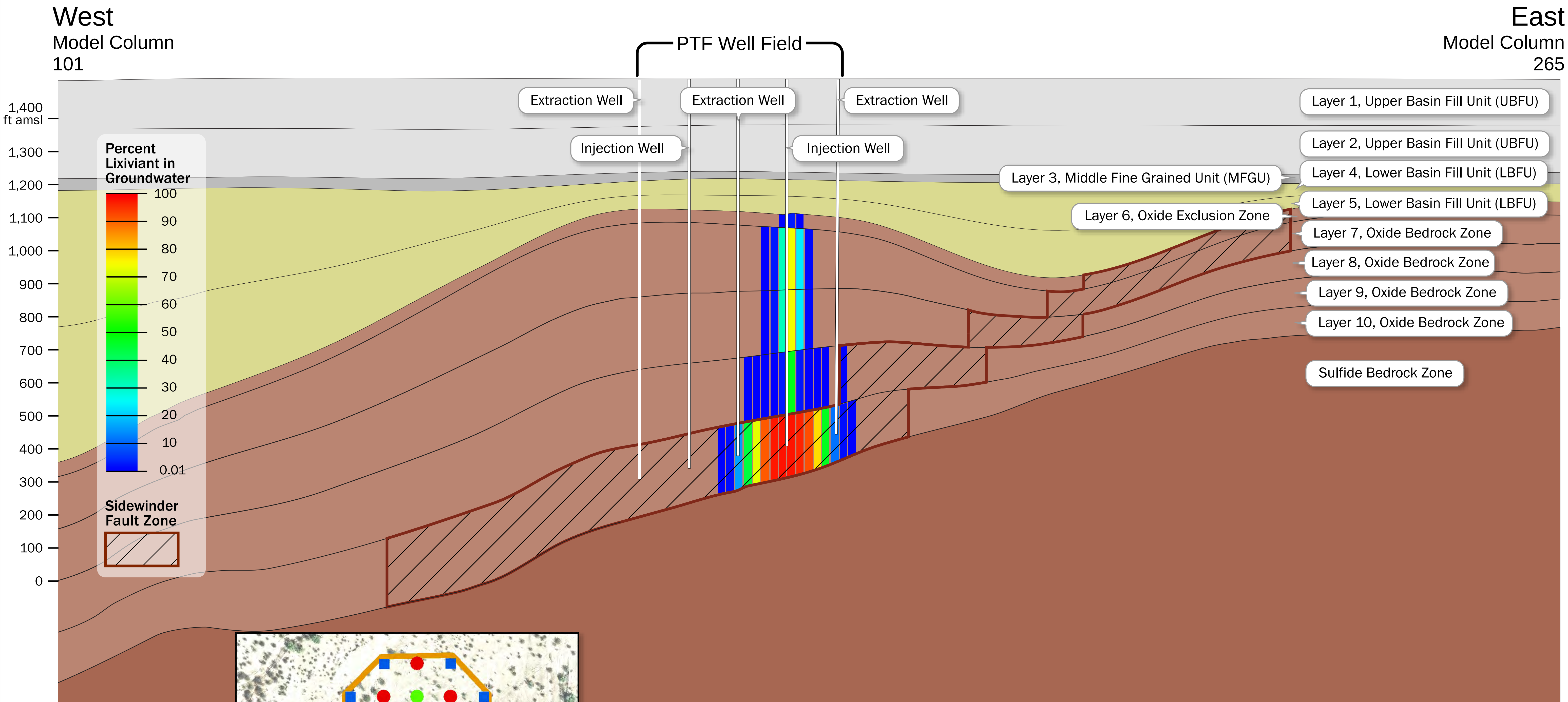
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Hydraulic conductivity of Sidewinder Fault Zone = 40 feet/day
- Porosity of Sidewinder Fault Zone = 13%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

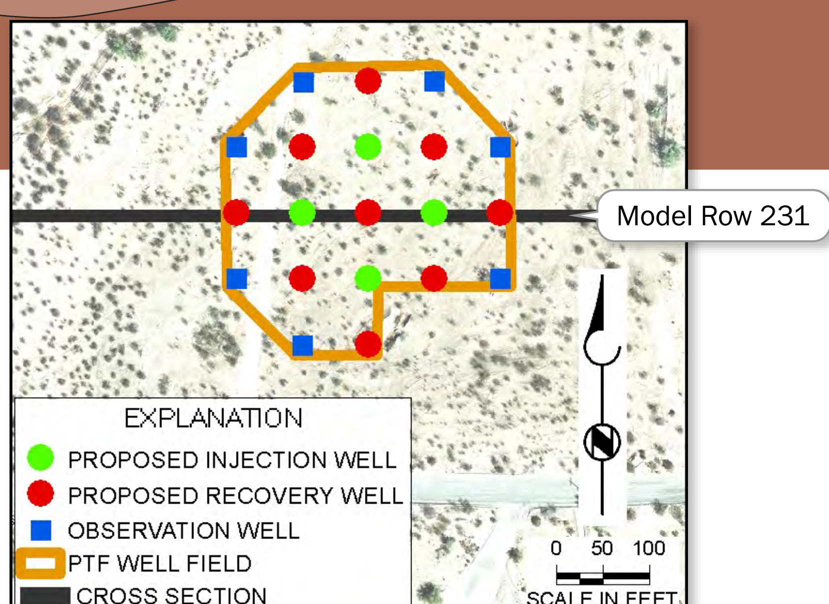
HORIZONTAL SCALE
(feet)
12.5 25
0 50 100 250

Brown AND Caldwell

Figure 2-3a
Model Predicted Migration of Lixiviant – Scenario 2
North-facing Cross Section
Florence Copper Project Groundwater Model

Cross-Section along Model Row 231





Scenario 3 Simulation Details and Variations from Base FCP Model:

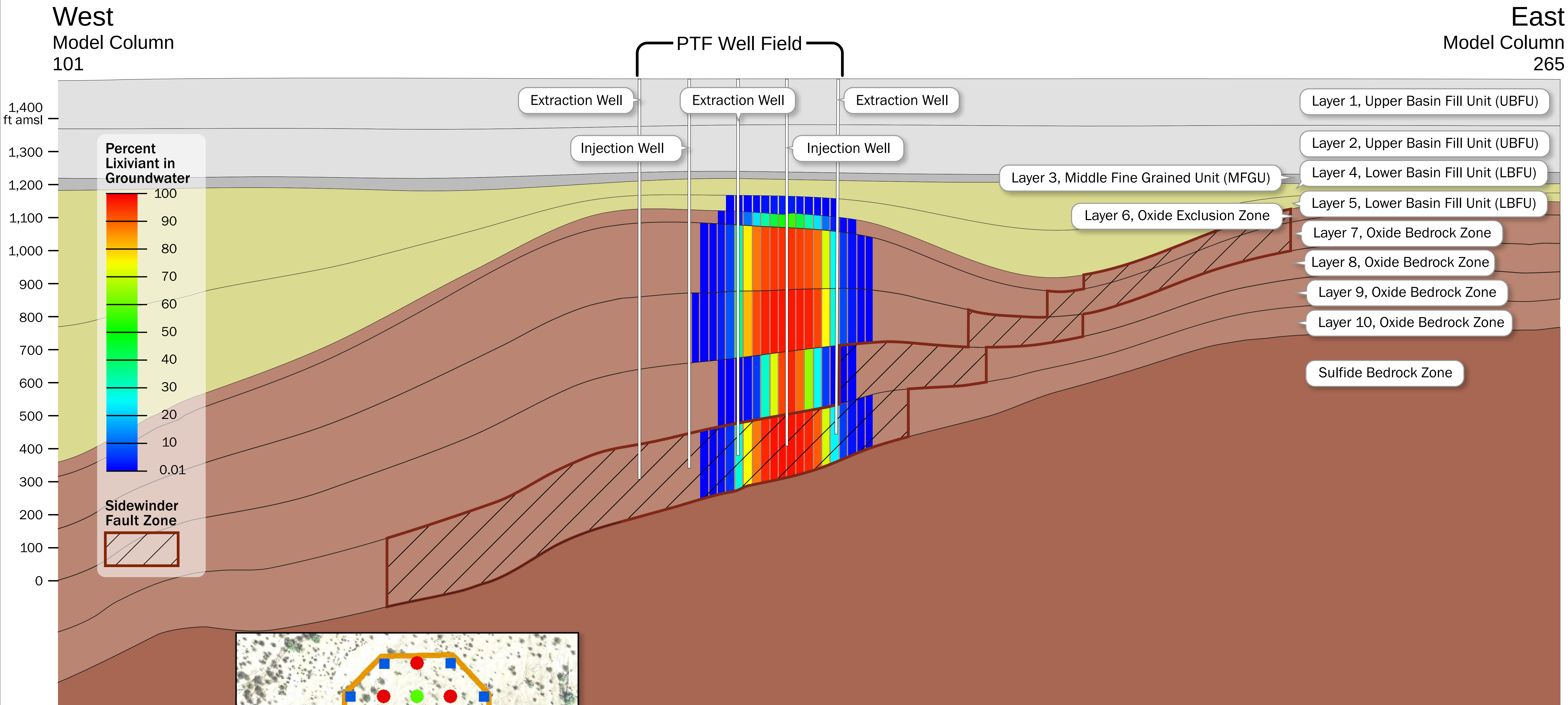
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Hydraulic conductivity of Sidewinder Fault Zone = 40 feet/day
- Porosity of Sidewinder Fault Zone = 20%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

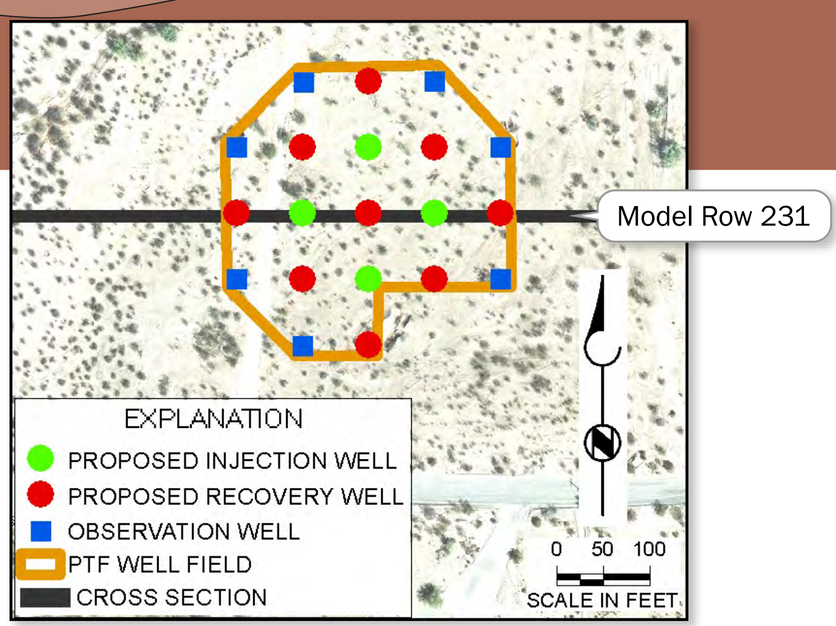
HORIZONTAL SCALE
(feet)
0 12.5 25 50 100 250

Brown AND Caldwell

Figure 2-4a
Model Predicted Migration of Lixiviant – Scenario 3
North-facing Cross Section
Florence Copper Project Groundwater Model

Cross-Section along Model Row 231





Scenario 4 Simulation Details and Variations from Base FCP Model:

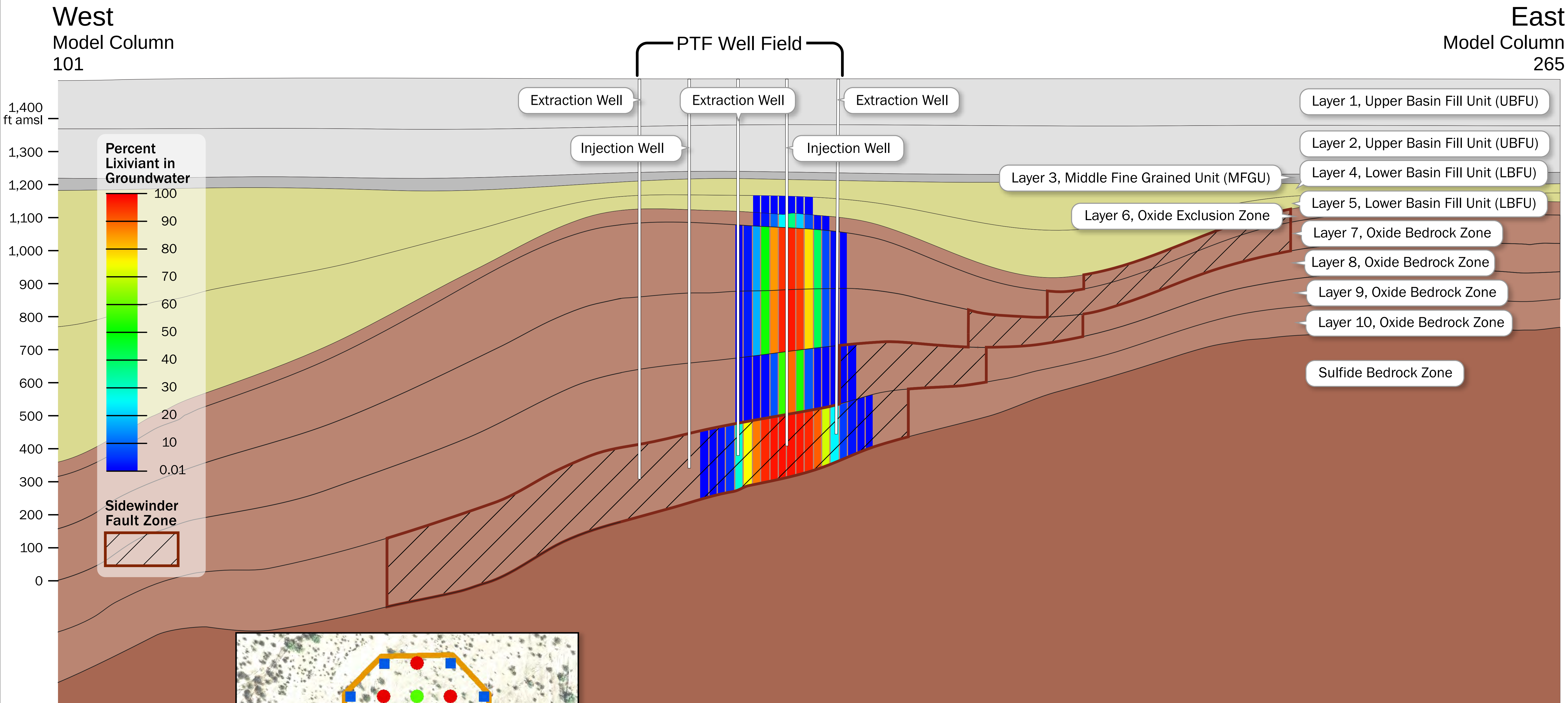
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Porosity of Oxide Layers = 2%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

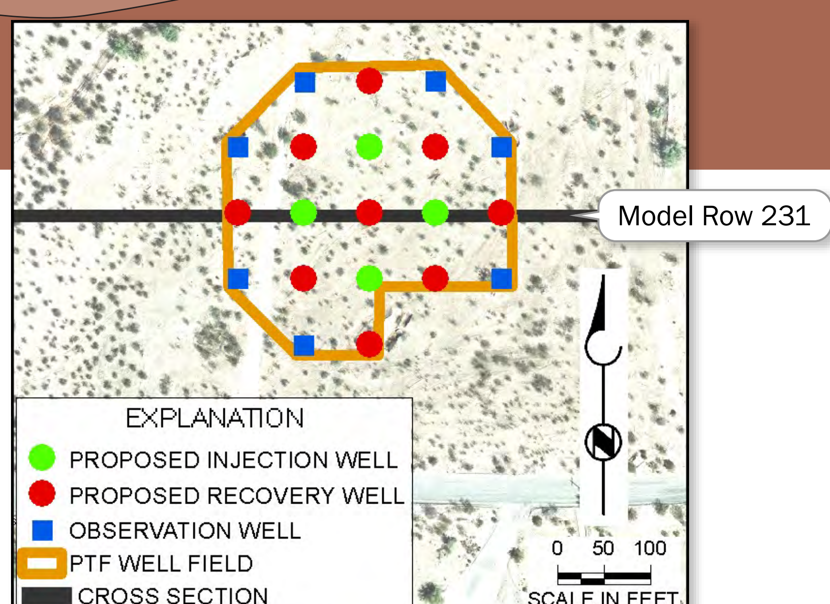
Brown AND Caldwell

HORIZONTAL SCALE
(feet)
25
12.5
0 50 100 250

Figure 2-5a
Model Predicted Migration of Lixiviant – Scenario 4
North-facing Cross Section
Florence Copper Project Groundwater Model

Cross-Section along Model Row 231





Scenario 5 Simulation Details and Variations from Base FCP Model:

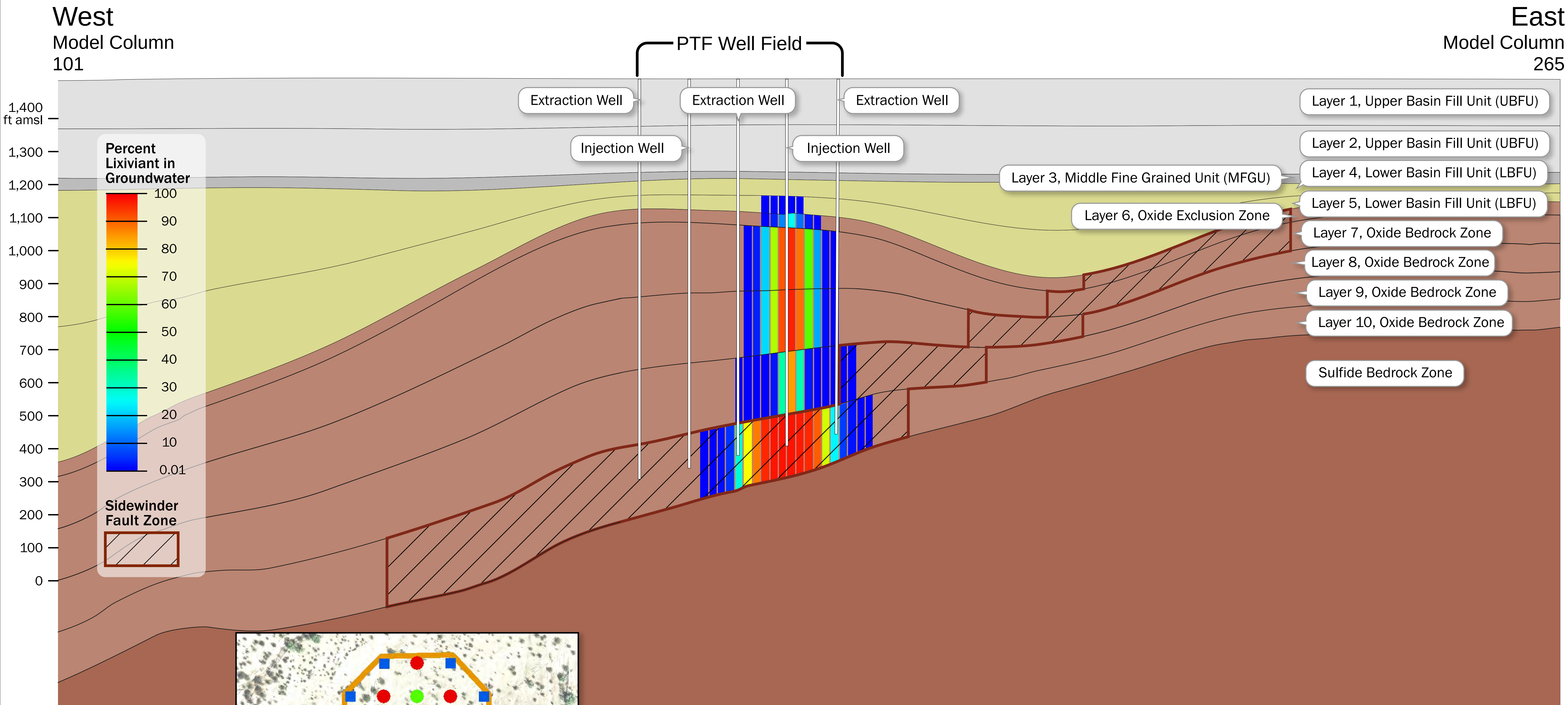
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Porosity of Oxide Layers = 8%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

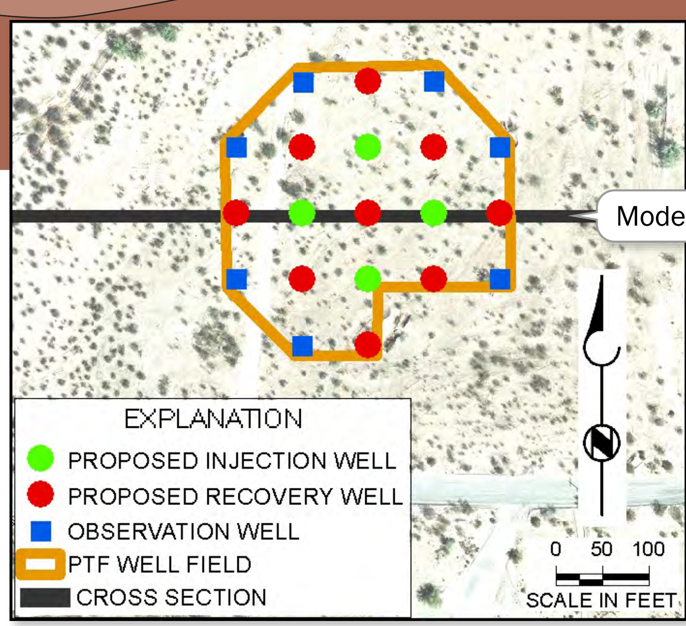
HORIZONTAL SCALE
(feet)
12.5 25
0 50 100 250

Brown AND Caldwell

Figure 2-6a
Model Predicted Migration of Lixiviant – Scenario 5
North-facing Cross Section
Florence Copper Project Groundwater Model

Cross-Section along Model Row 231





Scenario 6 Simulation Details and Variations from Base FCP Model:

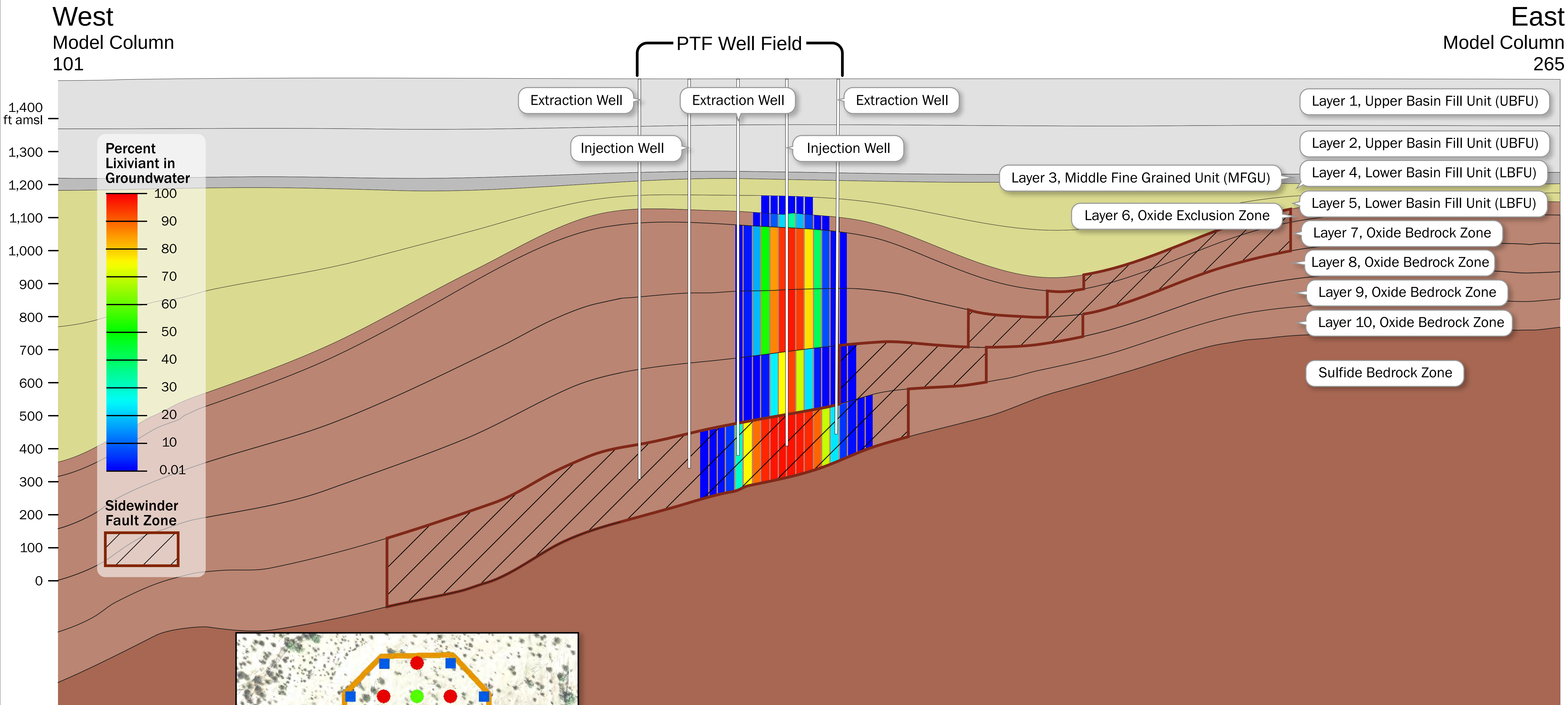
- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- Porosity of Oxide Layers = 13%
- Other hydrologic parameters same as base FCP Model (Table 10-1)

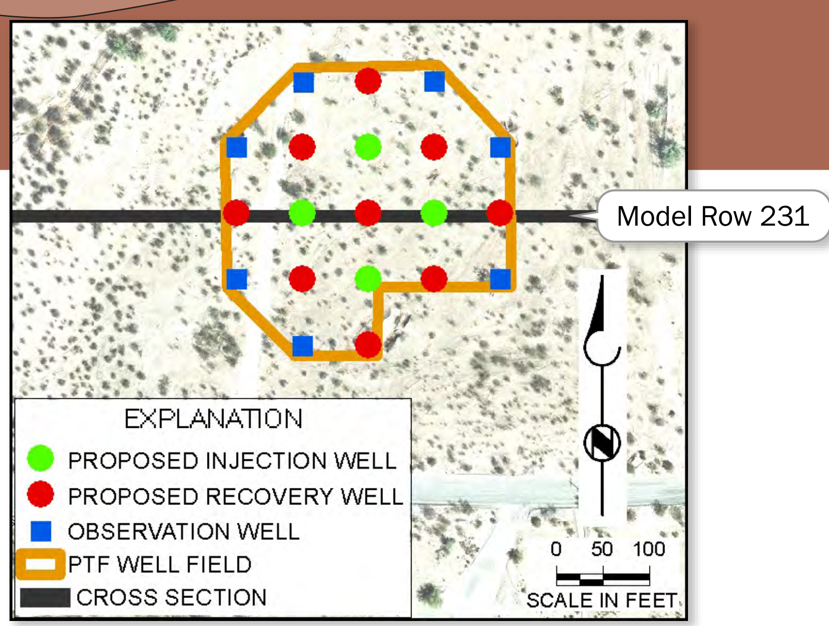
HORIZONTAL SCALE
(feet)
12.5 25
0 50 100 250

Figure 2-7a
Model Predicted Migration of Lixiviant – Scenario 6
North-facing Cross Section
Florence Copper Project Groundwater Model

Brown AND Caldwell

Cross-Section along Model Row 231





Scenario 7 Simulation Details and Variations from Base FCP Model:

- 30 days simulation time
- One well injecting at 60 gpm, no recovery pumping
- No confining unit in vicinity of PTF
- Hydraulic conductivity of MFGU (Layer 3) set to magnitude of LBFU
- Other hydrologic parameters same as base FCP Model (Table 10-1)

Brown AND Caldwell

HORIZONTAL SCALE
(feet)
0 12.5 25 50 100 250

Figure 2-8a
Model Predicted Migration of Lixiviant – Scenario 7
North-facing Cross Section
Florence Copper Project Groundwater Model

ATTACHMENT 3

Revised Operations Plan

CURIS RESOURCES (ARIZONA) INC.
ISCR PHASE 1 FACILITY OPERATIONS PLAN (REVISED)

Curis Resources (Arizona) Inc.
ISCR Phase 1 Facility Operations Plan (Revised)

1. INTRODUCTION

This document provides a description of monitoring, control, and reporting requirements associated with the operation of the Florence Copper Project (FCP) in-situ copper recovery (ISCR) Phase 1 facilities in compliance with an Underground Injection Control (UIC) Permit. The methods and procedures described in this Operations Plan incorporate the detailed provisions contained in Attachments H, K, O, and P of the application that Curis Resources (Arizona) Inc. (Curis Arizona) submitted to the United States Environmental Protection Agency (USEPA) on March 31, 2011 to transfer, with modifications of UIC Permit AZ396000001 (UIC Application). The injection and recovery system will employ devices for metering flow and pressure, and for manually or automatically shutting down flow when alarm conditions occur. The metering devices will be monitored in a central control room and will provide sufficient information to allow the operator to maintain hydraulic control on a daily basis. Within the control room, the operator will have direct access to the necessary controls for shutting down the injection and extraction systems in response to unanticipated conditions.

Table 1, *ISCR Phase 1 Facility Operations Plan (Monitoring and Response Requirements)* provides a summary of methods and procedures related to Phase 1 (Production Test Facility [PTF]) operations. The table identifies major components of the ISCR process; devices by which the components are to be monitored; the operating conditions to be monitored; possible causes of those conditions; immediate responses required if conditions exceed specified limits; and required follow-up actions. The monitoring devices will be electronically linked to the facility control room in order to provide a continuous assessment of conditions in the ISCR area, the pipeline corridor, and process area.

2. OPERATIONS

2.1 Pre-Operational Review

Before commencing ISCR operations, operations personnel will conduct a pre-operational review of all equipment, monitoring devices, and procedures to ensure that the operations comply with the following permit conditions.

1. Mechanical integrity tests (Part I and Part II) have been conducted on all ISCR wells in the ISCR well field, and all wells have passed the tests.
2. All wells have been completed such that they will not inject solutions within the uppermost 40 feet of the oxide zone (injection exclusion zone).
3. All coreholes and non-Class III wells located within 500 feet of the PTF well block have been abandoned in accordance with the approved Plugging and Abandonment Plan.
4. Allowable injection pressure set not to exceed 0.65 pounds per square inch per foot (psi/ft) for each injection well.
5. Fresh groundwater has been injected, as needed, to assess the hydraulics of the injection and recovery patterns and to confirm that all monitoring devices and controls are in working order.

2.2 Injection System and Monitoring Devices

The injection system consists of individual injection wells, pumps, manifolds, piping, flow meters, and related controls. Manifolds will be used in Phase 1 to distribute lixiviant to injection wells and to collect pregnant leach solution (PLS) from recovery wells.

2.2.1 Injection Pressures

The proposed Class III injection wells may be operated in one of two modes: pressurized at the well head or under atmospheric well head pressures.

To ensure that injection pressures do not induce additional fracturing of the oxide zone, the UIC Permit established a fracture gradient limit of 0.65 psi/ft. Maximum injection pressures are determined by multiplying the fracture gradient limit (0.65 psi/ft) by the depth from the top of well casing to the top of the injection interval. This method of calculating maximum injection pressures reflects the pressure generated by the weight of the column of raffinate and an additional pressure applied by mechanical means to achieve the maximum allowable injection pressure at depth.

2.2.2 Injection Monitoring and Controls

Mechanical controls and monitoring devices incorporated into the injection system include:

- a pressure gauge at each injection manifold with set points;
- a flow meter at each injection manifold for measuring flow rates (gallons per minute [gpm]);
- a totalizing flow meter for measuring cumulative flow (gallons) into each injection manifold;
- an isolation valve at each injection well;
- a flow meter at each injection well for measuring flow rates (gpm); and
- a valve at each injection well for controlling flow.

A schematic depicting well field controls is included as Figure 1, and well controls as Figure 2.

Operators will use the gauges and meters at each injection manifold as devices for monitoring injection pressures and flows on a manifold-by-manifold basis. Allowable injection pressure will be calculated for each injection well. Actual pressures measured at each manifold will be compared to the maximum allowable pressure(s) for the well with the lowest allowable pressure, and will be adjusted as necessary to ensure injection pressures are within calculated allowable limits.

Every 24 hours, the totalized flows from all of the injection manifolds will be summed and compared to the summed totalized flows from all of the manifolds from recovery wells, hydraulic control (HC) wells, and injection and recovery zone (IRZ) restoration wells. If the summed total flow out of the IRZ exceeds the total flow into the IRZ, hydraulic control is confirmed. If the summed total flow out of the IRZ does not exceed the total flow into the IRZ, adjustments to recovery and/or injection flow rates will be made accordingly to restore hydraulic control.

Reduced flow in an injection well may be due to changes in formation characteristics or clogging of the formation or the well screens. A sudden increase in flow may indicate a break/failure of the well casing. If a casing breach is believed to have occurred, the operator will shut down that well by closing the well head isolation valve and will conduct relevant inspections. Inspections and related reporting will be conducted in accordance with Plans for Well Failures (Attachment O).

The injection and recovery systems will be connected to one or more tank farms in the ISCR area. The tank farms will include tanks fitted with a high-level alarm and level indicators. Both alarm and level indicator signals will be routed to the control room. An alarm will actuate if either a line fails or the tank high level is exceeded. The feed pump to the tank will be disabled automatically. Spilled solutions will be captured in a lined collection sump able to contain 110 percent of the volume of the tank and line. The spilled volume will be pumped back into the circuit for reuse.

Solutions pumped through pipelines located in pipeline channels between the ISCR area and the process area will be metered for flow and pressure. An electronic monitoring system will alarm if a pump fails, flow is interrupted, or flow is not in logical mode when a pump is activated. Loss of pressure or pressure exceeding a high setting will cause the pump to automatically shut down. In the event of such an occurrence, the plant operator will inspect the system. A broken line will be repaired within 72 hours and spilled solutions captured in spill control sumps in the lined channels will be pumped back into the process systems or to the water impoundment.

2.2.2.1 Recovery System Monitoring and Controls

The recovery system is similar to the injection system. It is comprised of individual recovery wells, pumps, recovery manifolds, piping, and related meters and controls, and includes:

- a continuous reading flow meter (gpm) at each recovery manifold;
- a totalizing flow meter (gallons) at each recovery manifold;
- an isolation valve at each recovery well;
- a flow meter at each recovery well; and
- a pressure transducer within perimeter and selected recovery wells for measuring head/water elevation within an IRZ (to assess hydraulic control).

The flow meters on the recovery manifolds will allow the operators to monitor recovery flow rates and use the data to compare against injection flow rates as described above. As necessary, recovery flow can be adjusted in the manifolds to ensure that flow out of the operational unit exceeds the flow of lixiviant and any other injectate into the operational unit. Inspections and related reporting will be conducted in accordance with Plans for Well Failures (Attachment O.)

2.2.2.2 Hydraulic Control

Hydraulic control must be maintained from the time that lixiviant injection begins until the groundwater quality in the IRZ has been restored to a quality that meets closure criteria in the Aquifer Protection Permit (APP) and the UIC Permit.

Hydraulic control is defined as a condition involving an inward groundwater gradient. It is maintained by pumping more solution from the IRZ than is injected into the IRZ, and is used to prevent in-situ solutions from migrating beyond the IRZ.

In-line flow meters will be used to monitor and verify that the volume of PLS pumped from recovery wells exceeds the amount of lixiviant injected to confirm hydraulic control. In addition, the presence of an inward hydraulic control will be monitored on a daily basis by comparing water levels in paired wells along the perimeter of the IRZ. Paired wells along the perimeter of the IRZ include an inner recovery well and an outer observation well. Hydraulic control is confirmed when the water level in the outer observation well is higher than the water level in the inner recovery well of each well pair.

3. OPERATIONAL MONITORING

Table 1 (attached) summarizes operational monitoring methods and procedures that will be used during Phase 1 (PTF) operations. Table 1 is designed to provide for the identification and correction of any problem related to the storage or flow of ISCR solutions before the solutions reach surface soils, the vadose zone, or groundwater outside the IRZ. The monitoring methods and procedures are also designed to monitor and maintain hydraulic control and thereby prevent ISCR solutions from migrating beyond the IRZ. Table 1 is not intended to cover the sampling and analysis of groundwater or ISCR solutions because of the complexity of the required equipment and procedures. However, references are provided in Section 1 for all related sampling and analysis requirements.

3.1 Emergency Response/Contingency Plan Requirements Emergency Conditions

The following conditions will cause activation of the contingency plan.

1. Spills of sulfuric acid, raffinate, or PLS outside containment structures that are in excess of the reportable quantities set forth in 40 CFR 302 et seq.
2. Loss of hydraulic control within an operational unit for more than 72 consecutive hours. For purpose of this requirement, loss of hydraulic control means that the amount of fluids injected during a 72-hour period exceeds the amount of fluid recovered during the same 72-hour period, and/or that the average head reading for any observation pair for a 72-hour period indicates a flat or outward gradient.
3. Failure of transducers in any observation pair for more than 72 hours.

3.2 Emergency Response Actions

The occurrence of any of the conditions described above will result in:

1. The activation of the notification procedures set forth in the APP.
2. Immediate containment of the spilled material, return of collected liquids to the process or to the evaporation ponds, disposal of contaminated soils in the water impoundment(s), and disposal of other debris in approved off-site facilities.
3. Immediate cessation of injection until such time that hydraulic control has been established and recovery wells have operated a sufficiently long period of time to compensate for the amount of fluid that was injected in excess of the amount recovered during the 72-hour period.

4. RECORDKEEPING AND REPORTING

Operational reporting will be conducted at two levels: daily and quarterly. Curis Arizona operators will complete a daily operations log that includes each of the daily monitoring requirements and calculations described above, and other entries related to the injection and recovery process. These logs will be maintained on site and be available for inspection for a period of two years. Quarterly monitoring reports will be submitted to the Arizona Department of Environmental Quality (ADEQ), and will include summaries of pertinent data from the daily operations log, as well as water quality sampling results for the point-of-compliance (POC) wells. Copies of the quarterly reports will be maintained on site until commencement of the post-closure period.

4.1 Daily Operations Log

The daily operations log will include the following:

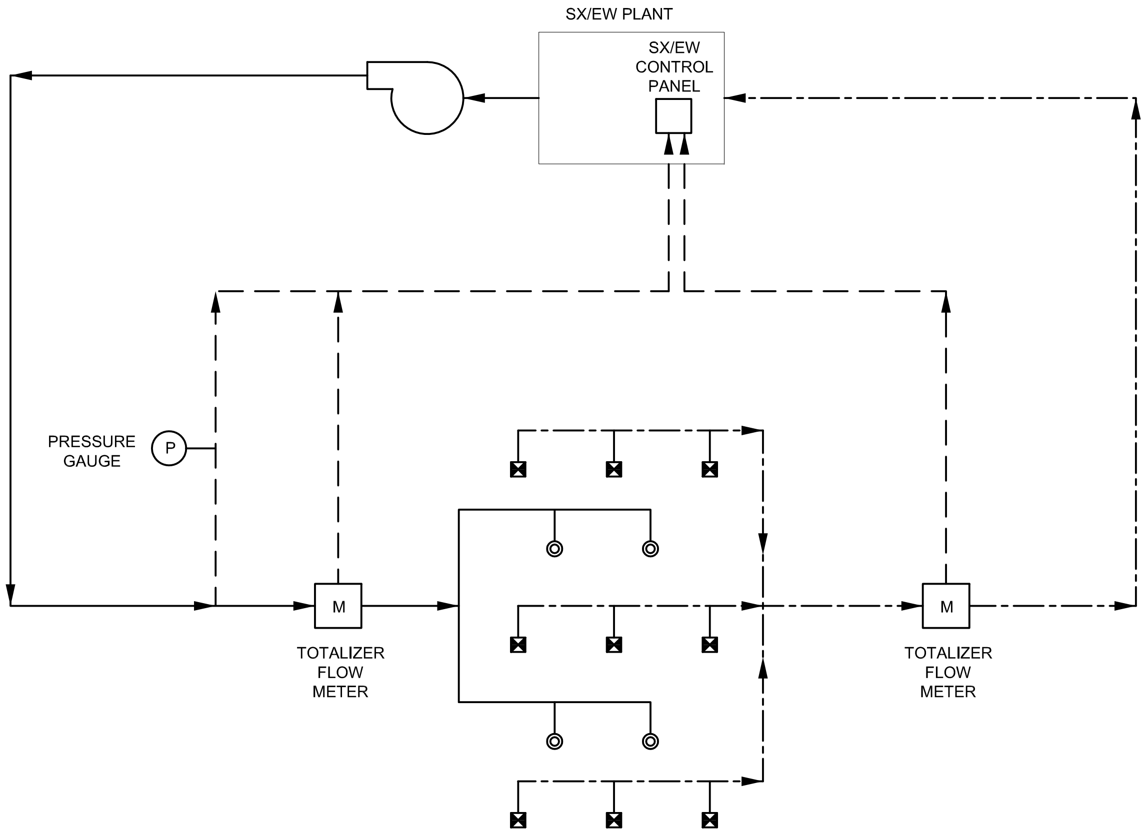
- Daily cumulative flow rates for each of the injection and recovery manifolds.
- Daily cumulative total flow rates for the all of in the injection and recovery manifolds combined.
- Daily average water level readings for each perimeter/recovery well pair.
- List of injection and recovery wells shut down in response to alarm conditions, and actions taken to correct the alarm conditions noted. This information will include well identification, shut down time, and estimate of excess injection flow occurring prior to shut down.

4.2 Quarterly Monitoring Report

Quarterly monitoring reports will be submitted to ADEQ and USEPA within 45 days following the end of each calendar quarter. The quarterly reports will include:

- A table showing POC monitoring well analytical results and alert levels with a narrative summary of those results.
- Results of monthly analysis of organics in raffinate.
- A table and graphs showing daily average head in the paired perimeter and observation wells.
- A table and graph showing daily cumulative injection and recovery flow in each active production unit over the reporting period.
- Results of monitoring required by 40 CFR 146.33(b)(i) whenever the injection fluid is modified to the extent that previously reported analyses are incorrect and incomplete.
- Results of mechanical integrity testing completed during the reporting period.
- A map showing current operational unit status.
- A list of wells and coreholes abandoned during the reporting period, and a list of wells and coreholes to be abandoned during the next reporting period.

C:\FILES\38706-002\38706-119-0000-INJ_RCVRY_SYS_CNTRL.DWG



LEGEND:

RECOVERY WELL

INJECTION WELL

HALEY & ALDRICH

CURIS RESOURCES (ARIZONA) INC.
FLORENCE COPPER
FLORENCE, ARIZONE

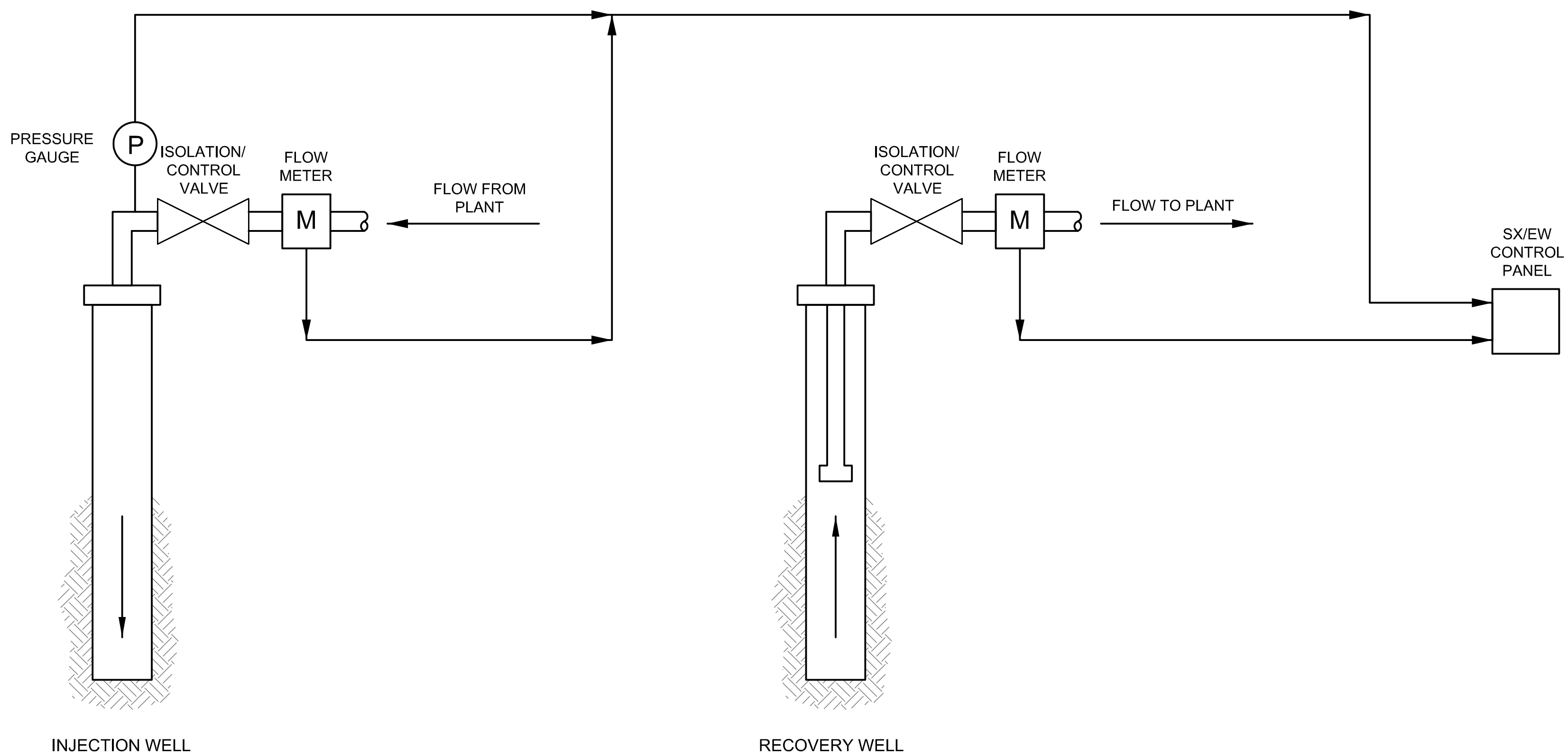
INJECTION/REOVERY SYSTEM OVERVIEW

HDI CURIS

SCALE: NOT TO SCALE
NOVEMBER 2012

FIGURE 1

C:\FILES\38706-002\38706-119-0000-INJ_RCVRY_SYS_CNTRL.DWG



HALEY & ALDRICH

CURIS RESOURCES (ARIZONA) INC.
FLORENCE COPPER
FLORENCE, ARIZONE

INJECTION/REOVERY WELL
SYSTEM CONTROLS

HDI CURIS

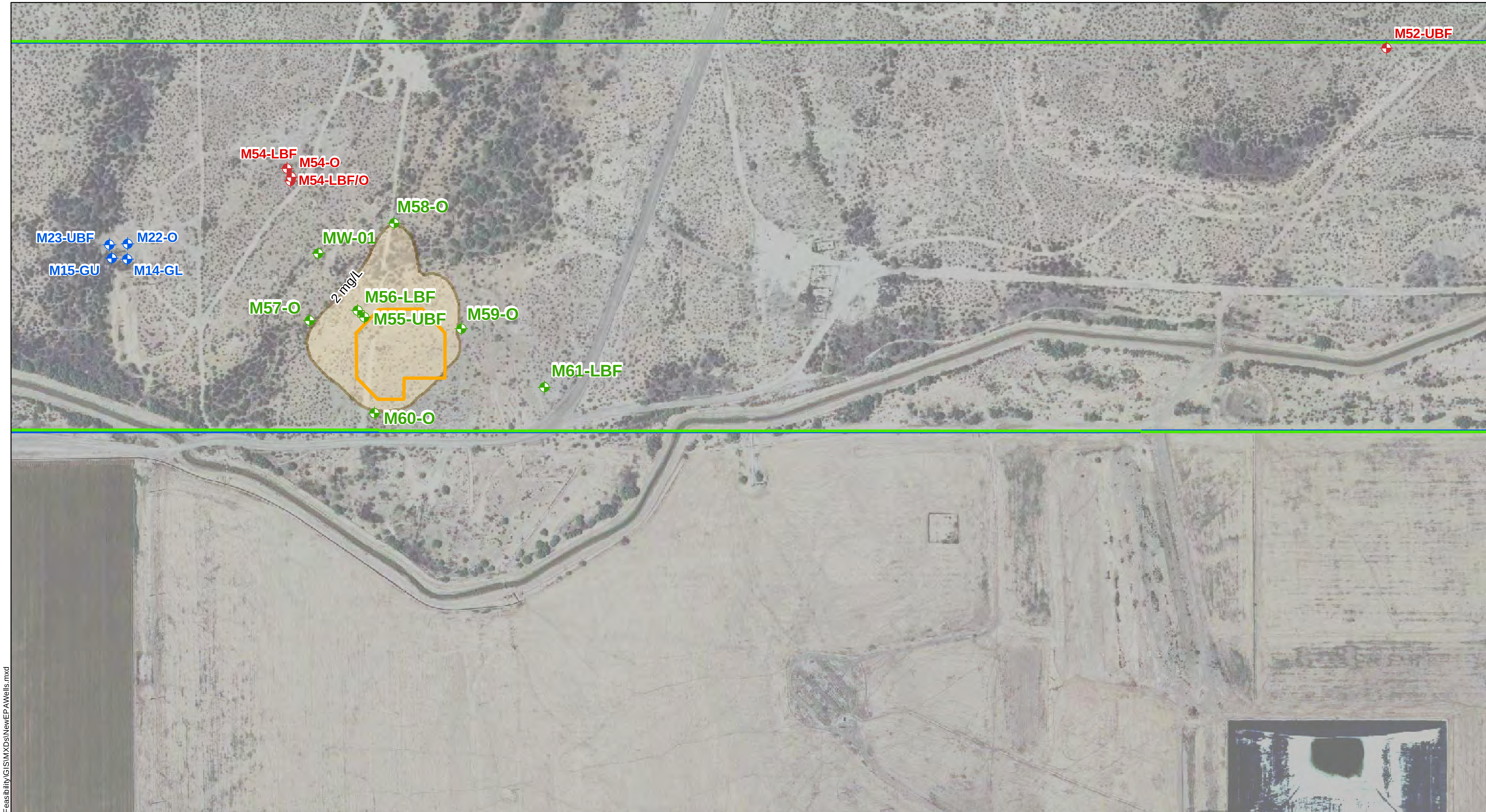
SCALE: NOT TO SCALE
NOVEMBER 2012

FIGURE 2

ATTACHMENT 4

Figure 11-1: Monitor Well Locations, Proposed Test Facility

Figure 11-2: Supplemental Monitoring Well M61-LBF Design



LEGEND

- PROPOSED SUPPLEMENTAL MONITOR WELL LOCATION
- EXISTING POC WELL LOCATION
- APPROVED NEW POC WELL LOCATION
- PTF WELL FIELD
- CURIS PROPERTY BOUNDARY
- STATE LAND LEASE
- MAXIMUM EXTENT OF SULFATE MIGRATION IN THE OXIDE 5 YEARS AFTER CLOSURE

N
W E
S

0 200 400 800
SCALE IN FEET

HALEY & ALDRICH

CURIS RESOURCE (ARIZONA) INC.
FLORENCE, ARIZONA

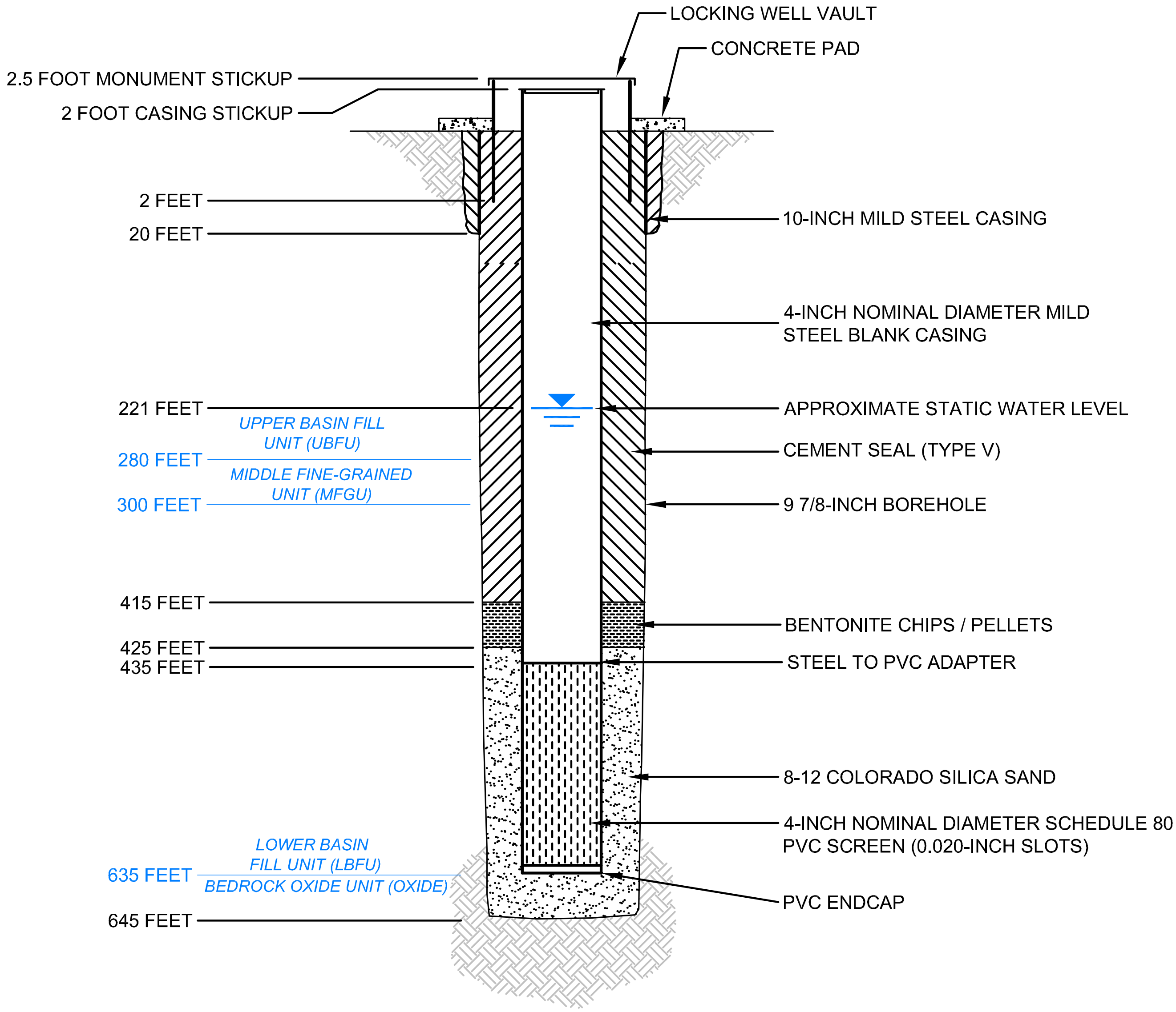
MONITOR WELL LOCATIONS
PROPOSED TEST FACILTY

HDI CURIS

SCALE: AS SHOWN
NOVEMBER 2012

FIGURE 11-1

G:\Projects\Curis Resources\38706-Curis Feasibility\GIS\MXDs\NewEPAWells.mxd



HALEY & ALDRICH

CURIS RESOURCES (ARIZONA) INC.
FLORENCE, ARIZONA

SUPPLEMENTAL MONITORING WELL M61-LBF DESIGN

HDI CURIS

SCALE: NOT TO SCALE
NOVEMBER 2012

FIGURE 11-2

G:\PROJECTS\CURIS RESOURCES\38706-CURIS FEASIBILITY\DRAWINGS\38706-M61WELLDESIGN.DWG

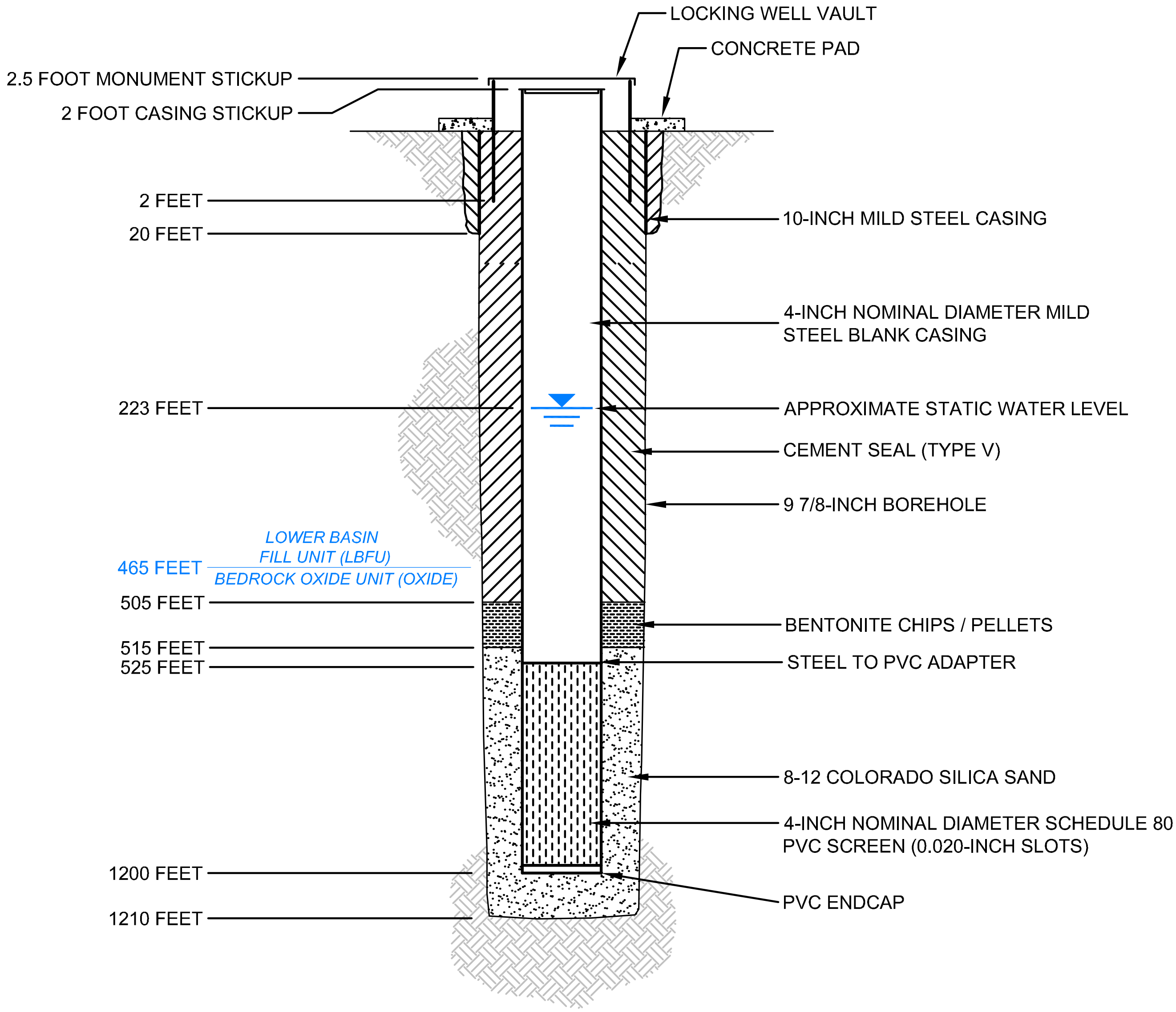
ATTACHMENT 5

Figure 12-1: Supplemental Monitoring Well M57-O Design

Figure 12-2: Supplemental Monitoring Well M58-O Design

Figure 12-3: Supplemental Monitoring Well M59-O Design

Figure 12-4: Supplemental Monitoring Well M60-O Design



G:\PROJECTS\CURIS RESOURCES\38706-CURIS FEASIBILITY\DRAWINGS\38706-M57WELLDESIGN.DWG

HALEY & ALDRICH

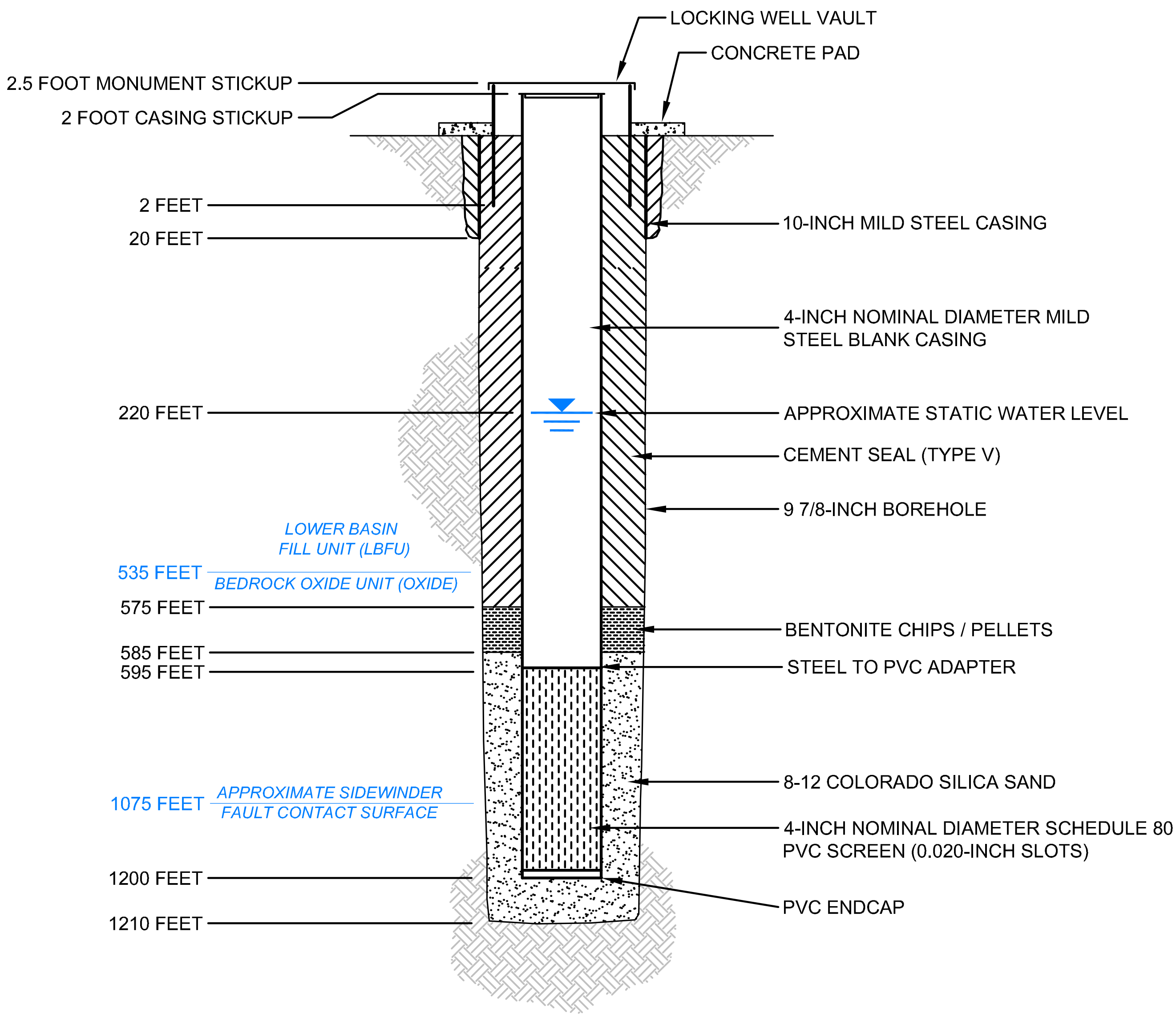
CURIS RESOURCES (ARIZONA) INC.
FLORENCE, ARIZONA

SUPPLEMENTAL MONITORING WELL M57-O DESIGN

HDI CURIS

SCALE: NOT TO SCALE
NOVEMBER 2012

FIGURE 12-1



G:\PROJECTS\CURIS RESOURCES\38706-CURIS FEASIBILITY\DRAWINGS\38706-M58WELLDESIGN.DWG

HALEY & ALDRICH

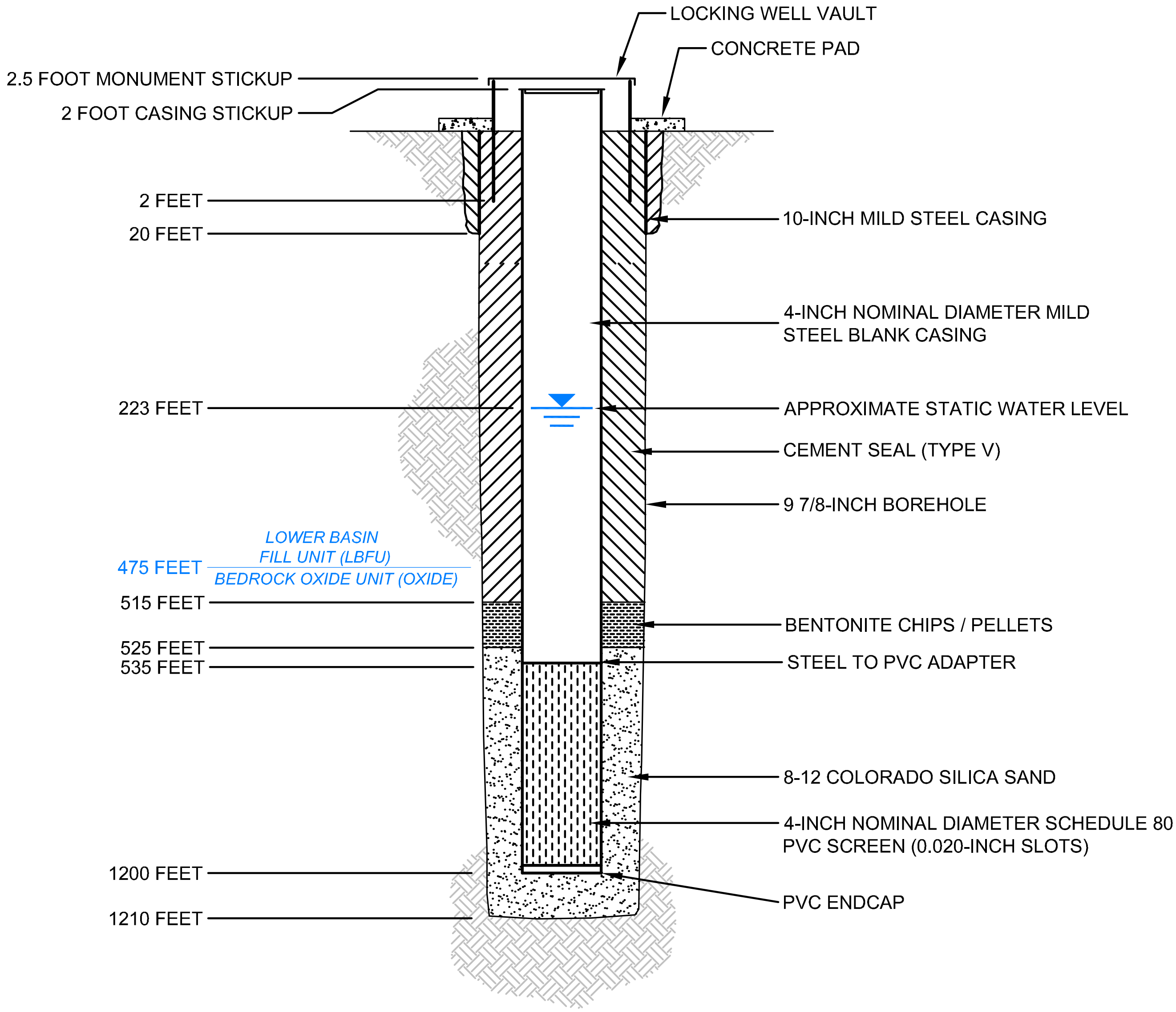
CURIS RESOURCES (ARIZONA) INC.
FLORENCE, ARIZONA

EPA SUPPLEMENTAL MONITORING
WELL M58-O DESIGN

HDI CURIS

SCALE: NOT TO SCALE
NOVEMBER 2012

FIGURE 12-2



HALEY & ALDRICH

CURIS RESOURCES (ARIZONA) INC.
FLORENCE, ARIZONA

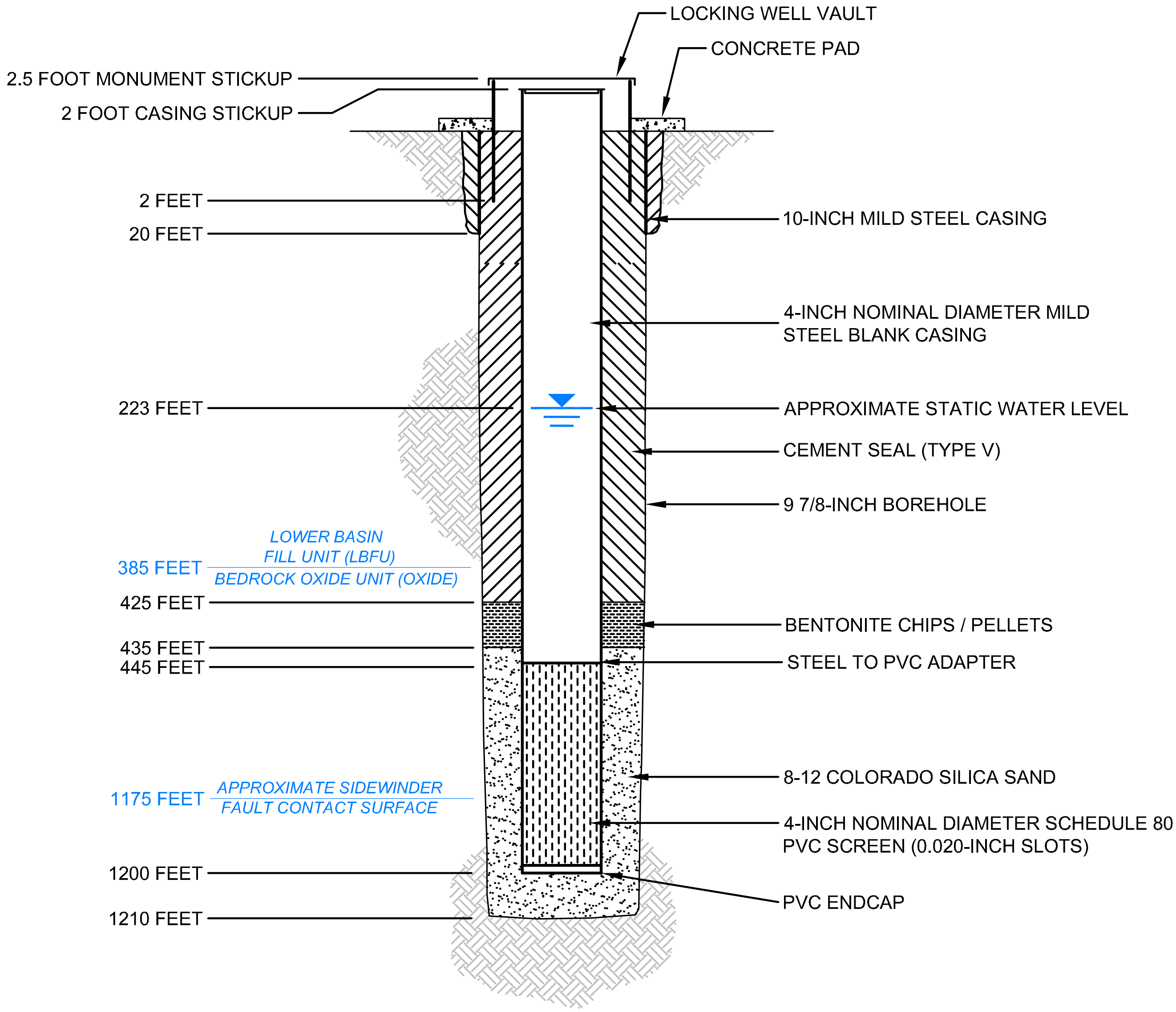
SUPPLEMENTAL MONITORING WELL M59-O DESIGN

HDI CURIS

SCALE: NOT TO SCALE
NOVEMBER 2012

FIGURE 12-3

G:\PROJECTS\CURIS RESOURCES\38706-CURIS FEASIBILITY\DRAWINGS\38706-M59WELLDESIGN.DWG



G:\PROJECTS\CURIS RESOURCES\38706-CURIS FEASIBILITY\DRAWINGS\38706-M60WELLDESIGN.DWG

HALEY & ALDRICH

CURIS RESOURCES (ARIZONA) INC.
FLORENCE, ARIZONA

SUPPLEMENTAL MONITORING WELL M60-O DESIGN

HDI CURIS

SCALE: NOT TO SCALE
NOVEMBER 2012

FIGURE 12-4